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Winter 1982

Fluidized Bed Combustion

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Electric Perspectives

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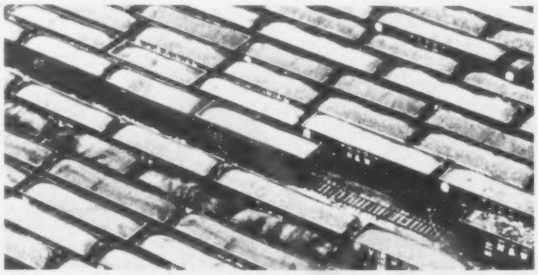

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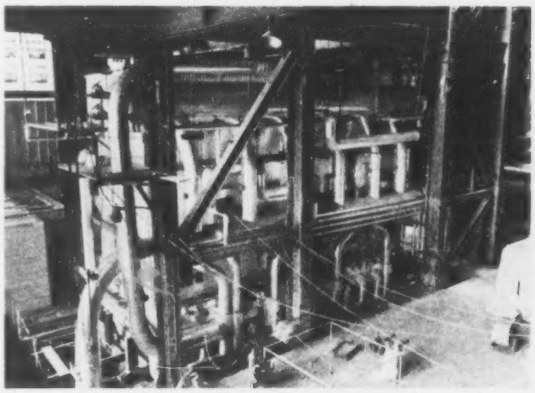

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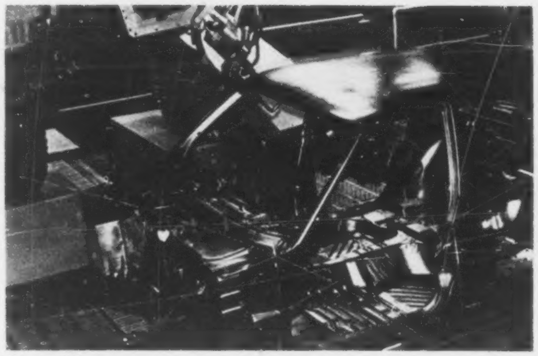

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Cover: An impressionistic rendering of TVA's pilot plant where a test program is bringing fluidized bed combustion to the forefront of commercially promising generation technologies.

Illustration by Michael J. McGurk

The (Uncertain) Route to Railroad Deregulation and What It Will Cost Utilities

By Frederick C. Dunbar

It won't take an act of Congress to deregulate railroad rates—forthcoming court and ICC rulings may do it

A few years ago, very few people thought the nation's railroads would be deregulated. Times have changed. The mood in Washington is for deregulation, and recent Interstate Commerce Commission (ICC) rulings implementing the Staggers Rail Act of 1980 reflect that mood. These rulings have created the possibility that most railroad rates on coal will be freed, effectively, from regulated ceilings. This outcome is by no means inevitable— some key issues have yet to be decided by the courts and the ICC—but the chance of its happening should not be ignored by electric utilities.

The stakes are large. The railroads earned about $6.0 billion in revenues for hauling coal in 1981; of this amount, utilities paid about $4.7 billion. Even without deregulation, these revenues should grow at least 45 percent by 1990 as coal traffic increases because much of the growth in traffic will come from Western coal deposits requiring a long haul to users.

If railroads become deregulated, their earnings from coal traffic will become much larger. Though precise forecasts are impossible, plausible estimates show deregulated freight rates for coal would be anywhere from 30 to 60 percent higher than regulated rates. In 1981, this would have translated into an extra delivered coal cost to utilities in the range of $1.4 to $2.8 billion—8 to 16 percent of total delivered coal fuel costs. Because of growth in coal traffic, these extra rail costs would go up even further over the remainder of the decade: by 1990, the additional annual cost to utilities of deregulated rail rates would be $2.0 to $4.0 billion (in 1981 dollars). These additional costs easily could exceed the impact on the utility industry of other major regulatory decisions such as the 1977 Clean Air Act Amendments.

. . . by 1990, the additional annual cost to utilities of deregulated rail rates would be $2.0 to $4.0 billion. . . .

Routes to Deregulation

The railroads' campaign for deregulation is based on three widely-held beliefs they have parlayed into favorable legislation and ICC rulings. The first of these is that the railroads earn inadequate revenues; that is, they do not earn enough to make the investments necessary to support the nation's plan to use much more coal. The second is that coal prices have been rising faster than railroad rates as a result of the energy crisis. The third belief is that overly restrictive regulation has caused, or at least been a major contributor to, the railroads' revenue problems.

It is not clear whether it is important for any of these arguments to be true; it may be important only for the ICC and Congress to believe them. The first one—that railroads earn inadequate revenues—is held to be true mainly because the ICC has made certain rulings in favor of the railroads. In fact, railroad accounting procedures are such that nobody knows how many railroads are earning more or less than competitive profits.[1] However, it is a good bet that fewer railroads are earning inadequate revenues than the ICC believes. The second proposition—that coal prices have increased faster than rail rates as a result of the energy crisis—is flatly wrong. Presuming that the energy crisis can be dated from the Middle East war of 1973, rail rates have risen 168 percent, whereas coal prices have risen only 122 percent. Both have increased faster than the rate of inflation (see Table 1).

The last belief—that regulation has caused the railroads to earn inadequate revenues—may be true in part but is mostly irrelevant. There is no doubt that regulatory excesses imposed by Congress—specifically, those causing excess capacity, noncompensatory traf-

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Table 1. Producer Price Indexes for Railroad Coal Freight, Bituminous Coal, and GNP Implicit Price Deflator 1973–1981

	Producer Price Index		GNP Implicit
	Railroad Coal Freight	Bituminous Coal	Price Deflator
	(1972 = 100)		
1973	102.9	112.7	105.7
1974	120.2	172.0	114.9
1975	137.8	196.0	125.6
1976	155.0	186.2	132.1
1977	164.3	196.9	139.8
1978	177.2	217.8	150.0
1979	207.1	228.5	162.8
1980	241.4	236.3	177.4
1981	275.9	250.1	193.6[1]
Percent Change:			
1973–1981	168.1	121.9	83.2
Yearly Average	13.1	10.5	7.9

[1] Preliminary figure.

Sources: Railroad Coal Freight—U.S. Bureau of Labor Statistics, reported in National Coal Association, *Coal Traffic Annual*, 1979; Bituminous Coal—U.S. Bureau of Labor Statistics, *Producer Prices and Price Indexes*, various issues; GNP Implicit Price Deflator—*Economic Report of the President*, 1982, Table B-3, p. 236.

fic and cross-subsidies—have contributed to the railroads' troubles.[2] These regulatory troubles are, of course, in addition to burdens caused by unfavorable market forces such as slow growth in intercity freight demand and the rise of the trucking industry. However, the railroad problem has been studied a great deal over the past 25 years, and there has been little or no evidence that maximum rate regulation has been a major factor in the decline of the railroads. It is far more important for regulatory relief to be directed toward rationalizing the railroad plant—primarily by removing excess capacity. In fact, this reform is well underway as railroads are making use of new Staggers Act freedoms to abandon marginal lines. If this continues to be done aggressively, there is no compelling evidence that rail rates would have to be deregulated further for the railroads to earn adequate revenues.

Even though the arguments favoring rate deregulation are less than compelling, the chance of its happening cannot be neglected. One way that it could occur is simply for Congress to abolish the ICC. Though this is being discussed on Capitol Hill, there are no concrete proposals at present for ICC sunset legislation, and discussions are focusing on motor carrier, not railroad, regulation. In any event, captive shippers would have a voice in the legislative proceedings and would argue for protection from monopoly pricing. Whether ICC sunset legislation would provide such protection is an open question.

Of more immediate concern are the ICC's procedures now in place for rail rate determination and how shippers can effect their outcome. These procedures implement the rate setting logic of the Staggers Rail Act of 1980. A description of rate regulation factors under Staggers shows, first, that there are a number of ways in which rail rates can be deregulated and, second, that the ICC has broad discretion in determining whether this will happen. The ICC's rulings on this matter will be the result of several important Ex Parte proceedings and court cases.

The Logic of Rail Rate Regulation under Staggers

It is perhaps easiest to visualize rail rate determination under the Staggers Act as a sequence of factors which affect the ICC's jurisdiction over, and its consideration of, each rail rate:

1. Is the traffic explicitly exempted from ICC jurisdiction?
2. Does the traffic move under a contract rate?
3. Is the railroad market dominant in the traffic to which the rate applies?
4. Is the rate increase within the "zone of flexibility" authorized by Staggers?
5. Is the rate "reasonable" under guidelines established by the ICC?

For a specific commodity, the railroads may apply directly for an **exemption from ICC regulation.** To receive an exemption, the railroads need to show that competition prevents them from abusing their market power or that the traffic in question is of "limited scope" (a phrase not clearly defined by the Commission but probably meaning relatively small in ton-miles and/or geographic range). If granted and upheld by the courts, an exemption would allow the railroad to charge whatever the traffic will bear. This is exactly what the railroads have attempted in export coal traffic. This request is now being considered by the ICC, which (at the time of this writing) is deadlocked on a decision.

Note that exempting rail rates from ICC jurisdiction can be expected to remove any remaining antitrust immunity on the exempted service. The potential to challenge rates on antitrust grounds may be of cold comfort to shippers, however, in light of comments in the export coal case filed by the Antitrust Division of the Department of Justice.[3] The Antitrust Division seems to be saying that it is all right to let railroads set monopoly prices and expropriate shipper profits as long as doing so causes no decline in coal output. Though this theory does not have a lot of legal precedent, the general position seems to be consistent with historical application of antitrust laws—namely, these laws address the problem of monopolization and other anticompetitive behavior, not the reasonableness of prices set by an existing monopoly.

If the export coal exemption is granted, it is possible the railroads will request deregulation of some domestic coal shipments. That is, one could construct a plausible scenario in which railroads will request an exemption for, say, all Midwestern coal traffic, then all Southern Appalachia coal traffic, and so on. By requesting exemptions for a series of smaller coal markets, each request is more likely to meet a favorable ruling than would a request for exempting all coal nationwide.

Although possible, this is an unlikely route to deregulation. It entails both a favorable ruling on the export coal exemption (which the railroads seem to think they have the best chance to win) and a stiff fight from captive shippers in every other market. (It is worth noting that there is a tendency for the Commission to expand the geographic scope of its inquiries—as it did in the export case—causing even more shippers to become involved.) Other provisions of the Staggers Act hold more promise for proponents of deregulation.

A recent innovation in rate regulation is the ability for shippers and railroads to enter into **contracts** for rail services. These are the result of private negotiations between a shipper and a railroad covering such items as rates, minimum annual volumes, and coal handling procedures. In theory, contracts represent a liberalization of rate regulation which may provide benefits to both shippers and railroads. However, the price provisions of such contracts would clearly be negotiated in view of the regulated (filed) rates which a shipper could obtain without a contract. Consequently, posted regulated rates will be of overriding influence on the contracted rates with, obviously, adjustments for guaranteed volumes (by the shipper) and service (by the railroad). Once a contract clears the ICC's perfunctory review, however, disputes arising over the contracted rates are handled through state and federal courts, rather than by the ICC, where reasonableness of the rate is not a basis for its rejection. Therefore, contract rates are essentially deregulated, though in practice they will have ceilings imposed by existing tariffs.

Most of the remaining factors in rate determination address the question of whether a rail rate is "reasonable." At this time, there is no precise definition of reasonable rates—rather, they are determined on a case-by-case basis using evidentiary proceedings that take into account various factors. It is perhaps easiest to think of authorized rates as those between a regulated minimum and maximum. As a minimum, rail rates must contribute to the going-concern value of the railroad; that is, they must generate revenues which cover "directly variable cost." Though there is some controversy on this point, as a practical matter, virtually all coal rates will be above the legal minimum.

The maximum level for rail rates is much harder to define. First, it must be determined whether the carrier is **market dominant** in the traffic to which the rate applies. Market dominance is itself a concept which is not well defined by the ICC or the Staggers Act. However, the Staggers Act establishes certain circumstances under which a carrier is deemed not to have market dominance. If these conditions are violated, then market dominance is determined in an evidentiary proceeding.

Market dominance is itself a concept which is not well defined by the ICC or the Staggers Act.

A carrier is presumed not market dominant when the rate under dispute yields revenues which are less than certain specified percentages of variable cost. This revenue to variable cost

In 1981, utilities used 597 million tons of coal. They depended on railroads to haul about 414 tons of it.

percentage was 160 at the time the Staggers Act became effective and then increased 5 percentage points for each of the 3 years thereafter. It is 170 percent now (the period beginning October 1, 1982 and ending September 30, 1983) and will be 175 percent from October 1, 1983 until September 30, 1984. In subsequent years, the revenue to variable cost percentage will be no less than 170 percent nor more than 180 percent as computed by the ICC using a cost recovery formula written into the Staggers Act. It should be noted that rail rates at these levels often will be greater than the carrier's fully distributed cost. As a rough rule of thumb, revenues equal to 180 percent of variable cost are about 120 percent of fully distributed cost.

This market dominance test effectively deregulates rail rates which are now less than 170 percent of variable cost (or, in the future, as high as 180 percent of variable cost). For this reason, the market dominance standard has been referred to as a jurisdiction test—rail rates under these revenue-to-variable-cost limits are simply removed from ICC jurisdiction. In addition, of course, a railroad can be found to lack market dominance even if its rates exceed these levels—this outcome depends on the evidentiary proceedings.

If a railroad is found to lack market dominance, then it can charge whatever the market will bear. Otherwise, maximum regulated rates will be determined by two other major considerations. The first of these is the zone of rate flexibility allowed by the Staggers Act and the second is an independent determination of whether the rates are reasonable.

Within a **zone of flexibility,** the Staggers Act allows certain rate adjustments to existing and new rates even if the traffic to which the rate applies is market dominant. Briefly stated, these adjustments include the following: first, quarterly inflation adjustments which are proportional to the increase in railroad variable costs as measured by an American Association of Railroads Index; second, an additional 6 percent per year over the 3 years following the approval of the Staggers Act up to a cumulative maximum of 18 percent; and third, after 1984, an additional 4 percent per year if the railroad is not earning adequate revenues.

Except for the inflationary rate increases, these adjustments are not automatic. For example, if the adjustment results in a rate which is either 20 percentage points above the revenue-to-variable-cost market dominance test or above 190 percent, the Commission on its own initiative or on complaint from other interested parties may investigate whether the rate exceeds a reasonable maximum. The result of such an investigation will be a determination of whether the rate is reasonable.

This final issue to be decided—what is a **reasonable rate**—is potentially the most ambiguous one. Here, the Staggers Act gives relatively little guidance. In recent years, maximum rail rates have been based largely on cost of service concepts. This has involved setting a rate equal to a ratio of revenue to variable cost (ill-measured) such that the rate bears a general relationship to fully distributed cost. The Commission has all but decided that it will change these procedures in the future—though the exact formula to be used is, as of now, unknown. Among factors to be considered by the Commission will be those in the so-called Long-Cannon amendment to the Staggers Act—whether there is a large amount of traffic not contributing to going-concern value, whether there is a large amount of so-called marginal traffic (the rates for which could be raised), and whether one commodity is paying an unreasonable share of the fixed cost of the carrier. In addition, the railroads have argued that the Commission should consider whether the carrier is earning adequate revenues and the elasticity of demand for the traffic in question. This last factor is probably one of the more contentious disputes which the Commission must resolve in the near future; clearly, if railroads are allowed to raise their rates in proportion to the inelasticity of demand, then coal rates will have a much higher reasonable maximum than has been the case.

The Role of Ex Parte Proceedings

The ICC has interpreted the Staggers Act to give itself wide latitude in setting its policy towards maximum rate regulation. However, to render its policy requires a public hearing, much like an evidentiary proceeding, at which all interested parties can file comments. At present, three major issues (as well as several minor issues) of interest to utilities are either in the proceeding stage or are being litigated: market dominance, revenue adequacy, coal rate guidelines.

The way the ICC's rules to establish **market dominance** are presently structured, the shipper must show that competition affecting the rail rate is virtually absent. In the case of coal traffic, this means lack of competition from four sources: other railroads; other modes of transportation (for example, truck or barge); other geographic sources of supply; and other products (for example, other fuels). In general, the ICC has imposed a substantial burden of proof on shippers wishing to complain about high rates; it has expanded what was once a simple jurisdictional test into a full-blown antitrust-type inquiry.

An additional complication introduced by the Staggers Act is that rail rates well above marginal cost are not presumptive of market dominance. This is a reversal of the economic doctrine which defines market power in terms of the ability of a firm to raise its prices above marginal cost.

The inability of current market dominance procedures to withstand economic scrutiny has not gone unnoticed. At least two commentators, Professor Leigh B. Boske and Dr. William B. Tye, have concluded that a railroad often would be found to lack market dominance even though it has substantial market power.[4] Also, various shipper groups have appealed this ICC ruling to the courts, and it too may be remanded. Otherwise, it now appears that much coal traffic will be effectively deregulated if the current ICC approach stands court review.

The inability of current market dominance procedures to withstand economic scrutiny has not gone unnoticed.

The ICC has been quite generous to the railroads regarding **revenue adequacy.** Each year, the ICC must determine which rail carriers are earning adequate revenues. It has allowed the railroads to earn a rate of return equal to the current cost of capital on virtually all past railroad investment, including that which is artificially inflated by capacity exceeding current market needs or obsolete in relation to modern technology.

As Professor Alfred E. Kahn has described, if railroads charge rates to achieve this standard of adequate revenues, the result will simply be monopoly profits from captive shippers.[5] Procedurally, the ICC's determination of adequate revenues seems to have two effects on rail rate increases. First, railroads may be able to increase their rates more than they otherwise would under the zone of rate flexibility provisions of the Staggers Act. Second, the railroads could use the revenue adequacy determination as a way of setting higher coal rate guidelines than would otherwise be the case, despite the lack of any requirement in the Staggers Act to use the revenue adequacy determination in this way.

The U.S. Court of Appeals for the Third Circuit recently dismissed shipper attempts to overturn the ICC's rules on this issue. This means that future Ex Parte proceedings may be the only way utilities will be able to correct the ICC's current method.

Utilities also have a large interest in the outcome of proceedings regarding **coal rate guidelines.** As of now the railroads are arguing that demand-based pricing is appropriate and that, in some instances, they should be allowed complete pricing freedom even if they are found to be market dominant. To protect themselves from the rate increases which would follow if the ICC accepted the railroads' arguments, utilities should argue for safeguards to prevent railroads from abusing their monopoly power. Such safeguards would include application of certain cost standards to railroad ratemaking to prevent unrestricted demand-based pricing.

In summary, utilities may soon be in double jeopardy for increased coal rates.

The most recent substantive decision by the ICC in this proceeding (served December 21, 1981) shows the ICC does not have a firm notion of how maximum rates should be set.[6] The railroads argue that as long as they are earning inadequate revenues—as determined by the ICC's faulty methodology—they should be deregulated. The argument is based on the theory that a form of demand-based pricing—called Ramsey pricing—naturally emerges under deregulation and, moreover, is the most economically efficient pricing rule.[7] It is fair to say that the ICC was somewhat dubious of the railroads' argument; but, in its December 21 decision, the ICC also claimed it did not have any appealing counterproposals from shippers. That situation may have been remedied when, in April of this year, several shipper groups, including many utilities, filed alternative proposals for determining maximum coal rates (in addition to denouncing roundly the use of Ramsey pricing). This may have stalled, at least temporarily, the railroads' momentum toward deregulation.

There is some feeling that the forthcoming Coal Rate Guidelines decision will adopt an approach which attempts to merge some of the railroad and shipper viewpoints. This would call for application of the so-called stand-alone cost standard to rail rates.[8] This concept holds that no shipper should be forced to make a contribution to any part of the railroad not being used for its traffic. As such, it affords some protection to captive coal shippers who might otherwise be charged rates that are cross-subsidizing unprofitable rail segments.

On behalf of coal producers, I have argued before the ICC for a more stringent cost test—the application of marginal cost principles as is suggested under PURPA for electric utilities.[9] This idea has yet to gain widespread support, although the ICC claims, in its December 1981 order, to believe that cost of service must be a significant consideration in the establishment of maximum rate standards.

The ICC has promised a decision soon on this issue. Whatever the outcome, it is highly probable that some carriers and shippers will appeal the decision.

In summary, utilities may soon be in double jeopardy for increased coal rates. They already face an uphill battle in market dominance proceedings. Even if they win there, by showing that the carrier is market dominant and the traffic should remain regulated, they could lose in the maximum rate determination because under demand-based ratemaking the maximum rate will be whatever the traffic can bear.

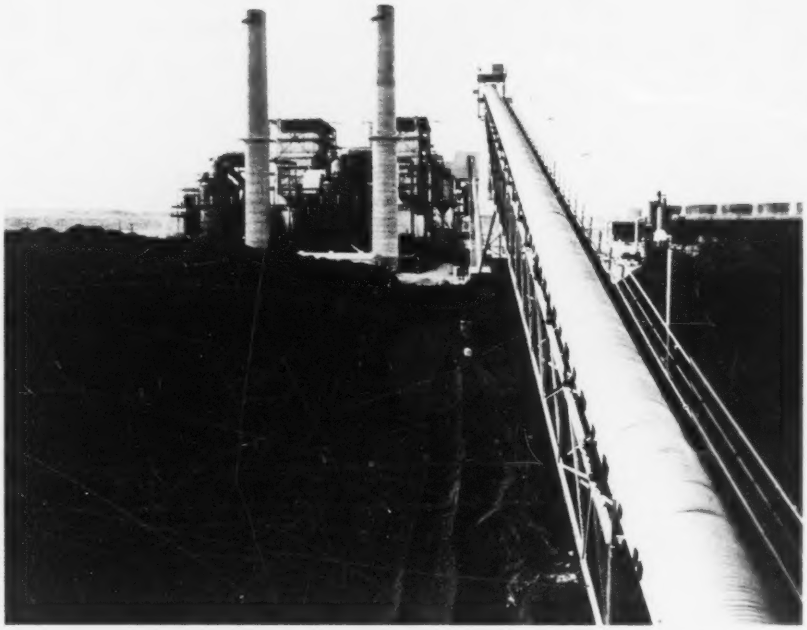
A number of other proceedings, while not directly effecting whether railroads will become deregulated, will also have an effect on regulated maximum rates. These include issues such as automatic inflation adjustments (under the zone of rate flexibility provision in Staggers) and the ICC's determination of the railroad's cost of capital (which is used to determine adequate revenues). In addition, there is a dispute on implementing the Long-Cannon amendment. It is clearly in the interest of utilities to participate in these proceedings.

Deregulation and Utility Fuel Costs

Although the available evidence is thin at best, one can make plausible estimates of railroad prices under deregulation. The *minimum* increase in rates can be estimated from the recent work of Professor Martin B. Zimmerman.[10] He computed that Western railroads offering new unit train routes charged 25 percent more in 1975 than the going rate on old routes. New routes encounter less regulatory resistance than old routes in the setting of maximum rates. However, in 1975 there was still some regulatory oversight on coal rates, so 25 percent should be considered a minimum likely increase in future rates. It is surmised by Professor Zimmerman that rates could have been even higher but for shipper complaints.

More recent evidence is available from several other sources. The first of these is a statistical study by Professor William E. Wecker which attempted to determine the Ramsey prices for coal movements on the Family Lines Rail System.[11] Using 1979 as a basis, his results show that the rates would increase 60 percent under Ramsey pricing. At about the same time, Professor Wecker also estimated Ramsey prices for Western railroads.[12] Again with 1979 as a basis, he determined that their coal rates would increase 71 percent, which was surprisingly close to his Family Lines estimate. Even so, whether his estimates can be applied nationwide is problematic; railroads and their service territories are unique, and it is dangerous to generalize the experience of one or a few to all the other coal-hauling carriers. Another, and probably more serious problem, is that the statistical errors associated with Professor Wecker's estimates are enormous. Consequently, the value he computes for the Ramsey price is subject to a large amount of uncertainty.

Another study of deregulated rail rates has recently been published by Professor Richard C. Levin.[13] For coal, he presents several possible estimates that range from 14 to 114 percent above the 1972 national average. The extremely wide range of estimates is due to three factors. First, and most important, are the assumptions made about interrailroad competition for coal freight. Specifically, if one assumes there is no competition (i.e., all shippers are captive), then Professor Levin estimates rate increases in the range of 53 to 114 percent; alternatively, if there is pervasive (though not cutthroat) interrailroad competition, he estimates rate increases in the range of 14 to 27 percent. The second source of variation in these estimates has to do with an econometric issue; in particular, Professor Levin made two different estimates of the demand for coal freight in 1972 and, *a priori*, was not able to determine which estimate was superior. A final, and minor, source of variation is caused by potential railroad cost savings from deregulation; if they occur, then he estimates that some portion would be passed on to shippers. Aside from the effects of these uncertainties on Professor Levin's estimates, there is another problem: he has estimated these effects using data from 1972. One should be highly circumspect in applying such results to conditions in the 1980s.



NERA estimates utilities will consume 734 tons of coal in 1990, about 27 percent more than was delivered to them in 1981.

The final study considered here was performed recently by National Economic Research Associates, Inc. (NERA) for the Coal Exporters Association and the National Coal Association.[14] This study estimated the increase in rates for *export* coal traffic if the railroads were deregulated. NERA found rates would rise between 30 and 60 percent over their 1980 levels. The wide range of these estimates is primarily attributable to uncertainty over the future competitiveness of U.S. coal abroad. If the world coal market is relatively competitive and the U.S. has a relatively low share, then the rail rate increases will be at the low end of this range. Under less competitive conditions, rail rates will be at the higher end.

Again, these results do not readily transfer to the domestic coal market. Under various circumstances, railroads in the utility coal market could have more or less market power than estimated for the export market. However, it is interesting that NERA's results fall in the ranges estimated by the others. (Note that all the authors are independent. In fact, NERA's study used a quite different methodology from the others; it simulated the world coal market to determine how railroads would behave, whereas the others relied on statistical estimates of railroad rate behavior.)

The question naturally arises as to which estimate can be used to predict the effect of deregulation on coal freight rates. Reviewing the range of estimates makes one very nervous about making any recommendation. However, a choice must be made in order to proceed with the analysis. Taking the NERA results as a reasonable compromise, let us make the rebuttable presumption that deregulation will cause rail rates to increase anywhere from 30 to 60 percent. How will the increase effect utility fuel costs?

. . . rail revenues from utilities will increase at least 45 percent by 1990 without further rate increases.

In 1981, domestic utilities depended on railroads to deliver about 414 million tons of coal: the utilities received about 345 million tons directly from railroads and received another 69 million tons on waterways to which the coal was transshipped by railroads.[15] Assuming that utilities paid the average revenue per ton for coal shipped by railroads for *all* uses ($11.31 per ton, according to data from the American Association of Railroads), this means that the total utility bill for rail services was about $4.7 billion (equal to $11.31 per ton times 414 million tons). Applying a 30 to 60 percent rail rate increase to this total yields an increase in the utility fuel bill of $1.4 to $2.8 billion for shipping the *same amount* of coal. That is, utilities would have paid in the range of $6.1 to $7.5 billion in rail freight charges for coal in 1981 had the railroads been deregulated.

Obviously, the increase in fuel costs would have been somewhat less than this because of moderating forces. For example, use of coal would have declined somewhat in response to the higher delivered price. Also, coal mine operators would bear some of the burden of increased rail rates through lower mine-mouth prices. These influences notwithstanding, the total cost increase is sizeable. For example, utilities spent a total of $17.6 billion on coal and its transportation by all modes in 1981.[16] The rail bill increases would have added another 8 to 16 percent.

Looking at the future, the cost of railroad deregulation will increase dramatically over the remainder of the decade. The total amount of coal used by utilities will grow and much of the growth will be from Western mines. This means that total railroad expenditures by utilities will increase as a proportion of their fuel expenses and so would the increment due to deregulation.

The magnitude of these increased costs by 1990 is difficult to forecast because there is no credible forecast of rail coal freight. However, an educated guess can be made by piecing together some of the available information. First, NERA's current forecast of 1990 utility coal consumption is only about 27 percent over 1981 deliveries (734 versus 581 million tons—note that deliveries in 1981 were less than consumption because of the miners' strike). However, it is conceded generally that the rail share of coal transportation will increase in the future as it has over the past few years. (Since 1979, the percentage of coal received directly from railroads by utilities has increased from 52 to 60 percent.[17]) Also, because coal will be shipped greater distances in the future, every 10 percent increase in tons shipped by rail is estimated to yield somewhat more than an 18 percent increase in ton-miles by rail.[18] Generally, rail rates do not increase in proportion to ton-miles because of terminal charges, but the railroads' total coal revenues will certainly increase proportionately more than tons shipped simply because the price of a long-haul is higher than the price of a short-haul.

As a general impression, these trends suggest that rail revenues from utility coal shipments will increase at least 45 percent by 1990 without further rate increases. This means that the increment due to deregulation could also increase by 45 percent over our 1981 estimate. That is, the 1990 cost to utilities from the ICC's actions would range from $2.0 to $4.0 billion (in 1981 dollars).

Financial impacts of this magnitude have usually been quite provocative to utilities. The utility industry has contested strongly the Montana coal tax and various provisions of the 1977 Clean Air Act Amendments. Yet, railroad deregulation could easily cost more than any of these, and utilities appear to be protesting it less.

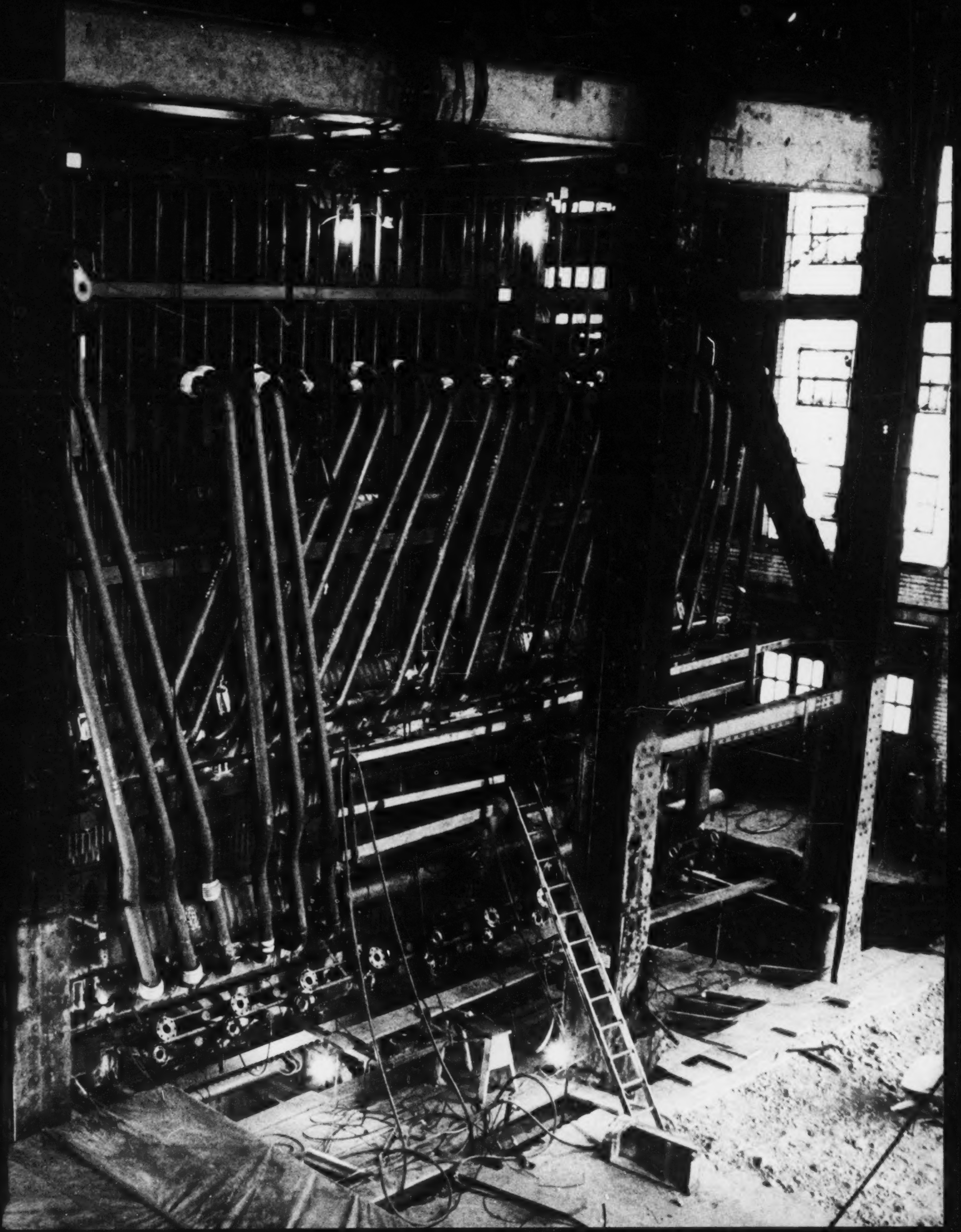
Although total coal freight rate deregulation is not a certain outcome of the various ICC and court proceedings, recent rulings on major issues such as revenue adequacy and market dominance have been in favor of the railroads. Maximum rates for coal traffic, now the subject of an ongoing ICC proceeding, appear to be headed in the same direction.

The opportunity for utilities to participate in determining the outcome of these and other deregulation issues is still available, though quickly disappearing. Should utilities fail in the regulatory process to achieve their goals for coal traffic, there is, of course, the option of returning to Congress and seeking revisions to the Staggers Act itself. However, given the current political climate and mood of Congress, the outcome of such an effort would be highly unpredictable.

. . . recent rulings . . . have been in favor of the railroads.

Notes

1. For discussions of problems in railroad accounting see U.S. General Accounting Office, *Accounting Changes Needed in the Railroad Industry* (Gaithersburg, Md.: February 4, 1981).
2. The operative legislation for rail regulation is the Staggers Rail Act of 1980, Pub. L. No. 96-448, 94 Stat. 1895 (1980). The procedures for granting an exemption are laid out in a fairly concise fashion even though a large amount of interpretation and discretion is given to the ICC. By comparison, the procedures for regulating rail rates are so complex and intricate they would daunt a cryptanalyst.
3. The Department of Justice position on the coal export exemption is given in Comments of the Department of Justice before the Interstate Commerce Commission, Washington, D.C., on Ex Parte No. 346 (Sub.-No. 7) *Railroad Exemption—Export Coal*, December 21, 1981. The problem of mounting an antitrust attack against monopoly pricing by railroads is discussed in Verified Statement of National Economic Research Associates, Inc. before the Interstate Commerce Commission on Ex Parte No. 346 (Sub.-No. 7) *Railroad Exemption—Export Coal* on behalf of Coal Exporters Association and National Coal Association, December 18, 1981, Chapter V.
4. Leigh B. Boske, "An Analysis of Recent Developments in Railroad Maximum Rate Regulation," *ICC Practitioners' Journal*, Vol. 48, No. 3, March-April 1981, pp. 294–311, and Verified Statement of William B. Tye on behalf of National Coal Association before the Interstate Commerce Commission, Ex Parte No. 347 (Sub.-No. 1) *Coal Rate Guidelines—Nationwide*, April 13, 1982.
5. Verified Statement of Alfred E. Kahn on behalf of National Coal Association before the Interstate Commerce Commission, Ex Parte No. 347 (Sub.-No. 1) *Coal Rate Guidelines—Nationwide*, September 16, 1981. My own testimony in the same proceeding dated April 12, 1982 reviews prior research on the railroad problem to show that maximum rate regulation has not been a major cause, if a cause at all, of the industry's financial woes.
6. The citation for the ICC's interim decision on coal rate regulation is Ex Parte No. 347 (Sub.-No. 1) *Coal Rate Guidelines—Nationwide* (served December 21, 1981), 46 Fed. Reg. 62958 (1981).
7. The railroads' economic case for Ramsey pricing and deregulation is in Verified Statement of William J. Baumol and Robert D. Willig on behalf of the five eastern railroads before the Interstate Commerce Commission in Ex Parte No. 347 (Sub.-No. 1) *Coal Rate Guidelines—Nationwide*, May 11, 1981.
8. Interestingly, the stand-alone cost concept was described in detail in Baumol and Willig's testimony: many railroads do not subscribe to its application, however.
9. This is in the April 12, 1982 testimony.
10. Martin B. Zimmerman, "Rent and Regulation in Unit-Train Determination," *Bell Journal of Economics*, Vol. 10, No. 1, Spring 1979, pp. 271–281.
11. Verified Statement of William E. Wecker before the Interstate Commerce Commission, *Increased Rates on Coal, Louisville and Nashville Railroad Company*, Docket Nos. 37063 and Sub. Nos. and Ex Parte No. 357, Vol. I, April 28, 1981, Railroad Respondents' Statement of Fact and Argument.
12. Verified Statement of William E. Wecker before the Interstate Commerce Commission on Ex Parte No. 347 (Sub-No. 1) *Coal Rate Guidelines—Nationwide* on behalf of the Western Railroad Association, May 7, 1981.
13. Richard C. Levin, "Railroad Rates, Profitability, and Welfare Under Deregulation," *The Bell Journal of Economics*, Vol. 12, No. 1, (Spring 1981), pp. 1–26.
14. Verified Statement of National Economic Research Associates, Inc. before the Interstate Commerce Commission on Ex Parte No. 346 (Sub.-No. 7) *Railroad Exemption—Export Coal* on behalf of Coal Exporters Association and National Coal Association, December 18, 1981, Chapter 4.
15. These data were tabulated for NERA by the U.S. Dept. of Energy. Other data on annual deliveries of coal to utilities were taken from U.S. Dept. of Energy, Energy Information Administration, *Coal Distribution* (Washington, D.C.: 1979, 1980, 1981).
16. The delivered price of coal to utilities is given in U.S. Dept. of Energy, Energy Information Administration, *1981 Annual Report to Congress: Volume Two: Data* (Washington, D.C.: May 1982).
17. See *Coal Distribution*. Projections of increased rail market share in coal traffic are in U.S. Dept. of Transportation and U.S. Department of Energy, *National Energy Transportation Study* (Washington, D.C.: July 1980), p. 33.
18. This is taken from National Transportation Policy Study Commission, *National Transportation Policies Through the Year 2000: Final Report* (Washington, D.C.: U.S. Government Printing Office, June 1979), p. 162.



Fluidized Bed Combustion: A Better Way to Burn Coal

By Marie Mastin Newman

Research efforts are advancing on several fronts toward the day when fluidized bed combustion will offer utilities a cheaper, cleaner way to burn coal

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During the past year, activity has accelerated in the national program to develop fluidized bed combustion for utility applications. Several milestones have been reached:

- In Paducah, Kentucky, last summer, the Tennessee Valley Authority (TVA) dedicated its new 20-MW (megawatt) atmospheric fluidized bed combustion pilot test plant. TVA and the Electric Power Research Institute (EPRI) will be cost-sharing a test program there to determine whether atmospheric fluidized bed combustion can be used reliably on the scale demanded by utilities.
- At seven utilities across the U.S., preliminary design and siting activities got underway for a commercial-scale demonstration atmospheric fluidized bed combustion plant—the final step in the development process.
- In Palo Alto, California, EPRI launched work on a concept for using pressurized fluidized bed combustion—the turbocharged boiler—that offers the prospect of shop-assembled utility boilers that can be rapidly installed in the field, thus minimizing construction time and costs.
- In Wood-Ridge, New Jersey, the Department of Energy (DOE) and the Curtiss-Wright Corp. continued construction of a 13-MW pressurized fluidized bed combustion facility to test a method of using pressurized fluidized bed combustion in conjunction with combined cycles—an approach which promises higher efficiencies to utilities.

The effect of this accelerated effort is to bring closer to reality the prospect of a fluidized bed combustion system that can be operated reliably and efficiently on a commercial scale in utility systems.

This prospect excites many utility officials, and with just cause. Fluidized bed combustion may aptly be described as a utility operator's dream-come-true for a coal-burning power plant. An advanced method of burning coal in a bed of limestone suspended in air, fluidized bed combustion offers numerous technical advantages. Such coal emissions as sulfur dioxide and nitrogen oxide are captured or controlled within the burning process itself and therefore pollution control equipment such as scrubbers is unnecessary. Fluidized bed combustion boilers can burn any grade of coal—even coal wastes—with no resulting fouling or slagging problems to the boiler tubes. And finally, fluidized bed combustion boilers are more compact than conventional boilers and are therefore projected to cost less.

Fluidized bed combustion may aptly be described as a utility operator's dream-come-true for a coal-burning power plant.

"We feel that fluidized bed combustion is just a better way to burn coal," states Kurt Yeager, director of the Coal Combustion Systems Division of EPRI. "It's an evolutionary improvement in our use of coal as a fuel and one which resolves many of the constraints that now face the utility industry."

Fluidized bed technology is not a new phenomenon. Fluidized beds have been used for years in industry to promote certain reactions. The fluidized bed process was developed in Germany in the 1920s and since then has been used for such applications as extracting gasoline from crude oil, roasting ore, and incinerating wastes. More recently, the technology has been adapted to combust fuel and produce heat or steam for industrial processes and space heating. Industrial-size fluidized bed boilers are on the market to-

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day for these purposes. DOE estimates that between 35 and 40 industrial fluidized bed boilers are now being built, designed, or operated in the U.S.

Utility applications offer a more complicated situation, however. Utilities demand high levels of reliability, efficiency, and availability for power generation facilities, and research officials agree that fluidized bed combustion has not yet inspired the level of confidence required for operation on large utility systems.

Technical uncertainties are being resolved and research officials are enthusiastic about the progress being made.

That picture is changing, however, and quickly. Through EPRI and the work of several individual utility companies, the electric utility industry has devoted considerable effort and resources to bring the technology to the point where it can be used reliably as part of utility generation systems. Technical uncertainties are being resolved and research officials are enthusiastic about the progress being made. In parallel, work is underway at the federal level under the sponsorship of DOE.

Before reviewing these national efforts in greater detail, it would be helpful to examine the process in more depth. Why is it so effective in controlling pollutants? How does it work? What are its other advantages?

Bubbling Mass of Solids

Fluidized bed combustion is just one application of fluidized beds. A fluidized bed is basically a mass of solids, such as sand or limestone, that is suspended upward by some force such as hot gas or air. The force causes the solids to churn and mix to the point where they resemble a boiling liquid. In fluidized bed *combustion*, a fuel such as coal is added to the churning mass within the fluidized bed and is ignited. Combustion occurs as the mass is suspended in air, and the combustion heat is transferred both to the walls of the bed enclosure and to water-filled tubes submerged directly in the burning mass of solids. The tubes in turn produce steam or hot water for industrial processes, heating, or generating electricity.

The fluidized bed process promotes excellent mixing of the constituents in the bed and this aspect tends to maximize the rate at which a reaction will occur, research officials explain. This characteristic, plus the relatively low temperature at which combustion can occur (1500–1700 degrees Fahrenheit as opposed to 3000 degrees Fahrenheit for a conventional pulverized coal boiler), gives rise to several key environmental advantages when coal is the fuel being burned.

For one, when coal is burned in a fluidized bed of limestone at this low temperature, a chemical reaction occurs which effectively captures within the boiler itself the sulfur dioxide that is produced during the combustion process, eliminating the need for scrubbers to remove the pollutant after combustion. During combustion the calcium carbonate in the limestone calcines (gives off carbon dioxide) to form calcium oxide. The sulfur in the coal oxidizes to form sulfur dioxide. These two components then react with each other to form solid calcium sulfate (gypsum), a byproduct that can be disposed of more easily than the sludge that results from scrubber operation.

The low operating temperature at which combustion occurs also inhibits the formation of nitrogen oxide, another pollutant from coal-burning that is regulated by environmental laws. "In a high temperature combustion flame, the nitrogen and oxygen in the air are excited to the point that they recombine to form nitrogen oxide," explains Richard Harrington, director of DOE's Office of Coal Utilization, Advanced Conversion, and Gasification. "If you can keep them from becoming thermally excited and combining in that way, you will form much less nitrogen oxide." And this is exactly what happens with fluidized bed combustion. At its operating temperature, the formation of nitrogen oxides is kept well below the level regulated by the Environmental Protection Agency.

Finally, for all the coal in the U.S., the temperature at which the fluidized bed combustion process occurs is below the temperature at which ash, a constituent of coal, melts and sticks on boiler tubes causing the high-cost maintenance and reliability problem of slagging and fouling (corrosion). With conventional pulverized coal boilers, utilities must be concerned about the ash content of the coal they burn. With a fluidized bed, that concern is unnecessary. Fluidized beds can tolerate a wide range of ash properties. One industrial fluidized bed combustion boiler operating in the U.S. today with DOE funding is burning anthracite culm—a coal waste containing 75 percent ash.

This ability of the fluidized bed boiler to burn low grade fuels suggests another advantage of the technology. "It's a potential combustor for materials that are being wasted now," states Howard Feibus, director of DOE's Coal Utilization Systems Division. "There are probably billions of tons of coal waste from conventional coal washing operations. Fluidized bed could turn this waste into a resource. It can burn dirty fuels in a clean way."

A final advantage of the fluidized bed boiler is its size. Because of the way the boiler is designed, it can be smaller than a pulverized coal system. In a fluidized bed boiler, tubes are run directly through the bed. Less space is required and therefore steam can be produced at somewhat lower life cycle costs than in a conventional pulverized plant with scrubbers.

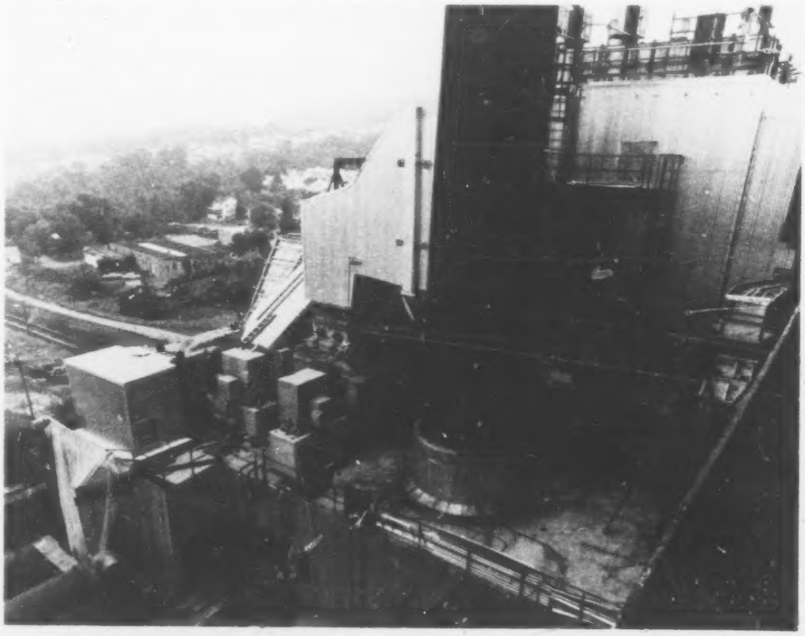
There are two basic types of fluidized bed combustion technology: atmospheric fluidized bed combustion and pressurized fluidized bed combustion. In the former, the process is operated at atmospheric pressure; in the latter, the pressure is increased. In terms of readiness for commercialization, the atmospheric bed is in the lead. Both private and federal efforts have been directed toward developing this technology for a number of years.

Atmospheric Fluidized Bed Combustion

Early federal efforts in the atmospheric fluidized bed area included the construction of several test beds in the mid-1960s. The largest of these was built in 1965 in Alexandria, Virginia, and ran until the fall of 1981. Information from this unit was used to scale up the technology to a 30-MW utility prototype boiler constructed at the Monongahela Power Company in Rivesville, West Virginia. Although there were a number of problems with the Rivesville unit, it provided basic information that was valuable in follow-on programs, notes DOE's Feibus.

In recent years, the bulk of the federal effort has been directed toward the industrial sector. As part of this effort, DOE has funded several successful industrial demonstration facilities, including one unit that began operating in 1979 on the campus of Georgetown University in Washington, D.C. The 100,000 lb/hr steam unit provides the principal source of space heating and cooling for the university and has been successful in meeting the strict air quality standards of the District of Columbia even though it burns high sulfur coal. Several other demonstration facilities are also operating, including one at the Great Lakes Naval Training Center near Chicago and a unit in Shamokin, Pennsylvania, that burns anthracite culm to produce steam for a nearby paper manufacturer. Because DOE feels that the atmospheric bed system is now a marketable technology, the agency is no longer conducting demonstrations in this area. Rather, it is sponsoring work on several advanced innovative concepts that might improve the performance of the technology over the long term.

EPRI and the utility industry have taken the lead in the effort to develop atmospheric fluidized bed systems for utility application. "We're trying to bridge the gap between the shortfalls of the development of atmospheric fluidized bed combustion for industry application versus utility application," notes William Howe, manager of fluidized bed combustion research and development at EPRI. "There are certain



A second generation demonstration project, the Monongahela fluidized bed combustion system operated from October 1976 to August 1982.

aspects regarding performance on the industrial level that are just insufficient for meeting the demands of efficiency and reliability necessary for utility applications."

One of these aspects, Howe explains, is combustion efficiency—primarily a measure of how much of the carbon in the coal (its principal source of energy) is utilized during the combustion process. In a small industrial boiler, 92–94 percent combustion efficiency may be acceptable, Howe notes. In a large utility boiler using at least 20 times the amount of coal, that figure would be insufficient.

Recycling is the key to achieving the high combustion efficiency and sulfur capture levels necessary for utility operation. . . .

A similar case holds true for sulfur capture. Utilities are required to meet more stringent levels for sulfur removal than are industrial units. "And sulfur control dictates the amount of limestone you use," Howe explains. "We want to keep that to a minimum."

Therefore, early in EPRI's atmospheric fluidized bed combustion program, researchers set out to reach target objectives of 99 percent combustion efficiency and 90 percent sulfur dioxide removal with a calcium to sulfur ratio of about 2 to 1 (meaning that 2 units of calcium would be needed to capture 1 unit of sulfur). "We had proven in design studies that the economics of fluidized bed combustion is greatly enhanced when you can meet those targets," Howe notes. "Our studies had shown that the overall busbar power costs of fluidized bed combustion are cost competitive with pulverized coal plants with scrubbers when you can meet those objectives. We knew we had to prove that we could meet those targets or else there would be insufficient incentive to develop the technology for utilities."

EPRI was successful in meeting those targets at its 2-MW 6 ft x 6 ft atmospheric fluidized bed combustion development facility at Babcock & Wilcox's Alliance (Ohio) Research Center. The $2 million facility began operating in 1977. "We made a number of modifications to the process at the facility that allowed us to meet our goals," states Howe.

One of the main lessons learned at that facility was the importance of recycling fly ash from the combustion process back into the bed for further combustion, Howe explains. "As the furnace churns and bubbles, gas gets carried out of the bed and in it are fine particles that still retain a lot of carbon and limestone that has not been fully sulfated [captured its maximum of sulfur]. There's a great deal of energy and useful purpose left in that material that can be achieved by recycling it back into the bed. What you're doing is allowing the carbon particles to have a longer residence time in the furnace—giving them time to burn out and release all of their energy. The same is true for the limestone particles. You're allowing them a longer residence time to become fully sulfated."

Recycling is the key to achieving the high combustion efficiency and sulfur capture levels necessary for utility operation, Howe explains. "It's the difference between 92–94 percent combustion efficiency and 99 percent efficiency. We just can't afford to throw that energy away on a large utility system."

Recycling is one of the processes that will be further tested during a four-year, $28.5 million test program that got underway last summer under the sponsorship of EPRI and TVA at TVA's new 20-MW atmospheric fluidized bed combustion pilot plant in Paducah, Kentucky. Although the facility in Ohio will continue to operate for at least the next two years to demonstrate the combustion of a wide variety of fuels, the technical emphasis of EPRI's program and the bulk of its research dollars have been shifted to the 20-MW facility.

The $68 million TVA facility was funded both from TVA's internal power funds and from direct Congressional appropriations. "A lot of money went into the plant to build it as a research tool," Howe explains. "There is a lot of extra instrumentation, test equipment and provisions for achieving data, that drive the cost up considerably. The $68 million cost is largely due to those testing provisions as well as to the great deal of flexibility built into the plant." Although steam will be produced at the plant of a temperature and pressure suitable to electricity generation, the boiler will not be tied to a turbine, at least during the early stages of the test program.

The pilot plant was built to provide engineering confirmation of process improvements developed at the Ohio unit and to provide the engineering basis for scale up to full commercial utility application. The main objective of the test program is to test the various auxiliary systems that would be part of the facilities—primarily those of recycling, feeding, and control.

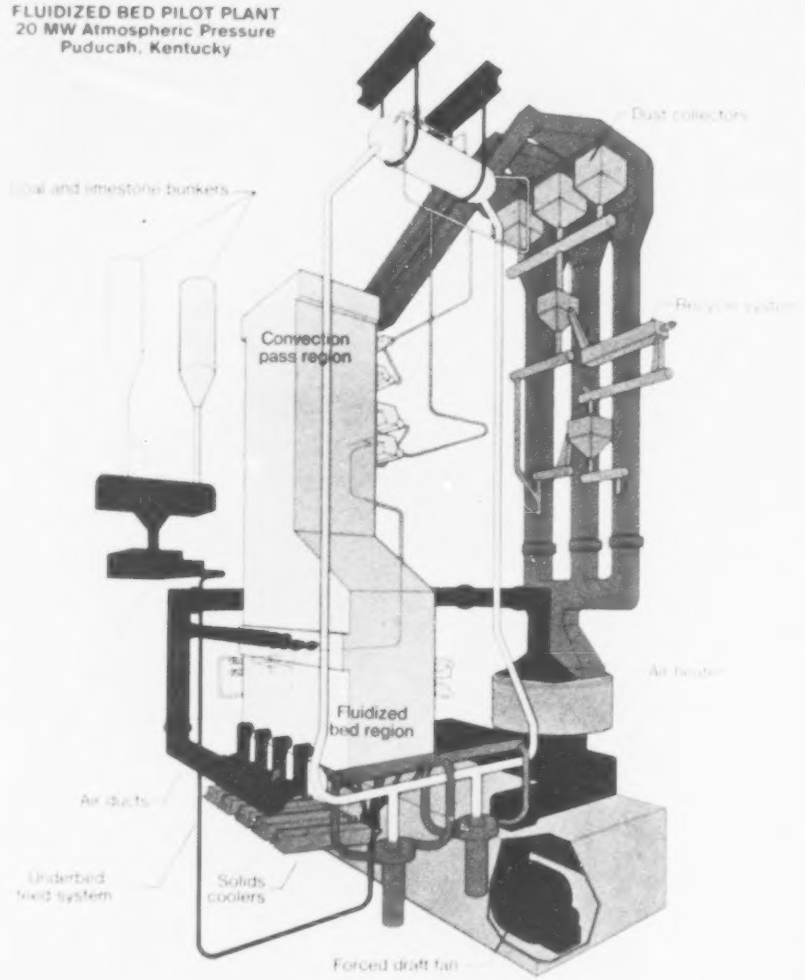
"The key to utility units for atmospheric fluidized bed combustion is not just the process performance itself, it's the reliability of the process in conjunction with all the auxiliary equipment that you need to feed the coal into the bed, drain spent material out, recycle the fly ash, and control the unit during cycling," says Howe. "We're concerned about the availability and reliability of those systems."

Examining various methods of feeding coal into a utility-size fluidized bed facility, for example, is a major objective. The coal can either be distributed at the base of the bed or over the top. For a large utility system, a lot of equipment is required—equipment that can malfunction and present reliability/availability concerns to utilities. The TVA facility has provisions to test both over- and underbed feed equipment.

Controlling the unit during cycling also presents technical concerns. "What we're trying to do is control the combustion process to meet the steam demand of the turbine and at the same time maintain the fluidized bed process at high combustion efficiency and sulfur capture levels," Howe explains.

The TVA facility is large enough to allow commercial utility-size auxiliary equipment to be attached to it for testing. Its size is comparable to one module of a commercial system that would be perhaps 200 MW.

The 20-MW test program will run through 1986. The step beyond that—and the final step in the development of atmospheric fluidized bed combustion into a commercial technology for utilities—is one or more 100-to-200-MW demonstration facilities. Planning for these facilities is already underway with EPRI acting as a catalyst and providing some financial support. In December 1981 EPRI sent a letter to a group of utilities to solicit interest in hosting and funding a utility-size demonstration project. Numerous responses were received and today seven utilities are proceeding with preliminary design work and siting activities toward a facility that would be ready to operate in the 1988–1990 time frame. These utilities are The City of Provo, Utah; Cleveland Electric Illuminating Company; Colorado-Ute Electric Association; Duke Power Company; Northern States Power Company; Puget Sound Power and Light Company; and the Tennessee Valley Authority. EPRI will be evaluating detailed proposals from these seven companies this winter and by spring will be in a position to recommend future courses of action to its Board of Directors, explains EPRI's Kurt Yeager. "We'd like very much to have more than one demonstration. Given the quality of the projects that have been proposed, we think it's altogether possible that there will be several very competitive projects that collectively will provide a confident basis


FLUIDIZED BED PILOT PLANT
20 MW Atmospheric Pressure
Puducah, Kentucky

The first coal firing of the TVA pilot plant occurred May 2, 1982, and full boiler load was achieved June 6, 1982. The boiler, constructed by Babcock & Wilcox, has a bed area of 216 square feet.

for industrywide use of atmospheric fluidized bed combustion."

The projects represent a wide range of atmospheric fluidized bed applications, Howe remarks. One utility proposes to take an old pulverized coal boiler, cut the bottom off, and put in a fluidized bed. The others are proposing either to build fluidized bed units at existing plants or to build entirely new grassroots facilities.

". . . This is almost a textbook way of bringing a new technology to commercial application."

Yeager stresses that the demonstration plant or plants will not be owned by EPRI. "These will be power plants that will run for 30 or 40 years. We want to help these utilities with the technical and financial support that will make it practical for them to proceed with their projects. We're trying to encourage and support the utility industry to use fluidized bed combustion and to achieve its advantages as quickly as possible."

Construction of the 200-MW demonstration facility or facilities could begin by mid-1984 and be completed by 1988–1990. After two or three years of operation, enough information should be available, EPRI feels, and the confidence level should be high enough, for utilities to broadly apply this technology.

Yeager feels strongly that the progress achieved in atmospheric fluidized bed combustion so far and its good chances for future success stem largely from the manner in which the technology has been allowed to develop. "We have in atmospheric fluidized bed combustion a technology that has been allowed to progress in a logical and carefully planned progression. We've gone in a step by step fashion from laboratory work to the 2-MW 6 ft x 6 ft facility to the 20-MW pilot plant and on toward the 200-MW commercial demonstration. Confidence has been gained at each step. This is almost a textbook way of bringing a new technology to commercial application."

Pressurized Fluidized Bed Combustion

Parallel to their work in atmospheric fluidized bed combustion technology, both the utility industry and the federal government are sponsoring efforts to develop pressurized fluidized bed combustion to the point where it will be acceptable to utilities for electricity generation. This second basic type of fluidized bed combustion technology is not as far along in development as the first, but it offers some particularly attractive features to utilities—the promise of higher efficiencies in one of its configurations and the prospect of modular construction and more rapid installation in another.

In one configuration, the pressurized fluidized bed boiler is pressurized and tied to a combined-cycle system. Because of the additional pressure, the hot gases from the combustor have enough energy to power a gas turbine which produces high quality waste heat. This heat in turn can be captured and used to drive a steam turbine, resulting in overall efficiencies for producing electric power of 39–41 percent, compared to a conventional pulverized coal plant with a scrubber that has an efficiency of about 34–35 percent.

The second configuration combines aspects of both atmospheric and pressurized fluidized bed combustion with combined cycles. This version of the technology is known as the turbocharged boiler. Like the combined-cycle configuration, the turbocharged boiler operates in a pressurized combustion chamber and is attached to both a gas and a steam turbine. Unlike the combined-cycle version, however, the gas turbine in the turbocharged boiler is not used to produce electricity. Rather, it is used to drive the compressor which pumps air back into the boiler to create the pressurized atmosphere. Electricity is produced by the steam turbine, which is connected to the boiler tubes in the combustion chamber, similar to an atmospheric fluidized bed combustion unit.

Up until about a year ago, EPRI had concentrated its pressurized fluidized bed efforts on the combined-cycle version of the technology. However, after a careful analysis of the current operating environment of the industry, which includes low load growth, high interest rates, and high cost of construction-work-in-progress, EPRI decided to shift its emphasis to a nearer term approach—the turbocharged boiler.

This approach is also a more conservative one, explains EPRI Project Manager Steve Drenker. "What we are proposing is considerably simpler than the combined cycle and doesn't have nearly as much technical risk in a number of areas. It can therefore be commercially available much sooner." EPRI envisions turbocharged boilers built and installed in the early 1990s.

The key advantage to the turbocharged boiler as EPRI sees it is its prospects for reduced costs because of shortened construction times.

"We see this technology as an opportunity to build shop-assembled, modular units that can be barge- or rail-transported from the factory to the field and rapidly constructed, thus minimizing the cost of work-in-progress," notes Kurt Yeager. EPRI expects that the turbocharged version will have particular attractiveness in situations where plants are being retrofitted from burning oil or gas to coal, or in situations where they are being uprated (increased in capacity).

Although the turbocharged boilers may be less efficient than combined-cycle pressurized fluidized bed boilers, they will also be less costly, EPRI maintains. The research organization reports preliminary findings that indicate that the capital cost savings of the turbocharged boiler cycle almost exactly offset the loss of efficiency "such that the bottom line net cost of electricity remains about the same as in pressurized fluidized bed combustion combined cycles," notes Drenker. Reliability has also been found to be substantially improved. These preliminary findings will be further scrutinized in a conceptual design and engineering study recently approved at EPRI.

Current plans call for a prototype turbocharged boiler plant to begin operating in the late 1980s. "This would be a plant that would operate on a utility system and produce revenue for its owner," Drenker says. "It would probably be an uprating or repowering [retrofitting] situation." Plant costs would be shared by the various participants in the project with EPRI assuming some of the risk or incremental costs beyond those associated with a conventional plant (redundant equipment, first-time engineering costs, extra margins). EPRI would also conduct a test program there.

EPRI considers its work on the turbocharged boiler to be a good foundation on which to build future efforts to develop the combined-cycle system if warranted. In the meantime, work to develop this longer-term version of the technology is progressing in several other areas.

DOE, for example, along with the Curtiss-Wright Corp., is funding the construction of a 13-MW pressurized fluidized bed combustion pilot plant in Wood-Ridge, New Jersey. DOE is contributing $56.75 million toward the construction of the plant, and Curtiss-Wright is funding $5.34 million to install the turbine and other equipment. The plant will begin operating in fiscal year 1984. DOE will not be involved financially in its operation, but will retain access to information obtained during the test program. Curtiss-Wright will seek partners from the private sector to sponsor the plant's operation.

DOE's Howard Feibus explains that the Wood-Ridge facility will be an integrated plant in the sense that its output of pressurized gases will be used to run a gas turbine and produce electricity. This will enable the operators to address the key technical problem with combined-cycle technology—the hot gas clean-up.

"As the pressurized air goes through the bed it picks up particulate matter that has to be cleaned so that it can run the gas turbine without damage to the blades at a very high rate. The real technological uncertainty of pressurized fluidized bed combustion [combined cycles] is whether you can take the hot gas from the combustor and satisfactorily run the gas turbine without rapid degradation of the blades. This is the kind of information we want to obtain from the Wood-Ridge plant."

In addition to the work with Curtiss-Wright, DOE is participating in an international test program jointly with Great Britain and Germany in Grimethorpe, England. There the parties are operating a pressurized fluidized bed combustor to test the process at the 250 million Btu/hr scale (an output equivalent to 25-MW of electricity). This experiment is not an integrated one, Feibus explains, in the sense that a gas turbine is not incorporated into the facility. Rather, the participants are hoping to learn additional information about the operation of the pressurized fluidized bed combustion process, its efficiencies, and its capital costs. Fei-

Current plans call for a prototype turbocharged boiler plant to begin operating in the late 1980s.

bus explains that a proposal has been advanced to add a turbine to the facility and run an integrated experiment, but that DOE feels that the Wood-Ridge plant will provide that kind of information. Therefore, although DOE is encouraging private industry to participate in such a follow-on experiment, the agency will not be part of it.

DOE feels that the combined experience of the Wood-Ridge and Grimethorpe plants will set the framework for the private sector to decide if it wants to continue work on the pressurized fluidized bed combustion combined-cycle process. One U.S. utility that has been very interested in the concept is the American Electric Power Company (AEP), which together with two European partners, has been working on the technology since 1976. As the largest coal user in the U.S., AEP became interested in fluidized bed combustion technology because of its environmental advantages, particularly its sulfur capture properties. The utility concentrated its efforts in the pressurized fluidized bed area, officials say, because the aspect of combined cycles offered the prospect of higher efficiencies. Also, AEP foresaw a lower capital cost for pressurized fluidized bed combustion systems because of the reduced size of the pressurized combustor.

Beginning in 1976, AEP joined with STAL-LAVAL Turbin (SL) A.B. of Finspong, Sweden, and British B&W Limited (BWL) of Great Britain, to embark on a feasibility study. The feasibility study was followed by a series of pilot plant test programs and design studies centering around the construction of a 170-MW demonstration plant that would be sited on the AEP power system at the Tidd Plant of Ohio Power Company in Brilliant, Ohio. In 1979, BWL elected not to continue in the development effort and was subsequently replaced by Deutsche Babcock Anlagen (DBA) of West Germany. The work of these partners led to the design of a 15-MW (Thermal) Component Test Facility in Sweden constructed by SL, DBA, and two other parties to investigate the integrated operation of the hardware that AEP is envisioning using in the demonstration plant. Although the test facility is not owned by AEP, the utility is funding a test pro-

Utility Reports Positive Experience With Small Fluidized Bed Boiler

One U.S. utility that is already generating electric power on a small scale using an atmospheric fluidized bed boiler is Northern States Power Company (NSP) in Wisconsin. NSP has retrofitted a boiler at its French Island Plant in LaCrosse, Wisconsin, with a fluidized bed boiler that burns wood chips. The plant went on line in December 1981 and now runs up to 14 hours a day using waste wood from local lumber companies. Although NSP did experience some problems initially with the unit, officials now view it as a positive experience and are looking toward a larger project using coal for the future.

NSP Manager of Power Production Tony Schuster explains that the utility had two primary motivations for going to fluidized bed at its French Island Unit 2 facility. The first one was economics—how to turn a plant that was a poor economic performer into one that would operate profitably again. The Unit 2 plant had originally come on line in 1948 using coal. In 1972 it was converted to oil for environmental reasons, and from that time on its operation decreased. By 1978 it was not operating at all except for performance tests. That was its future, Schuster explains, unless an opportunity came along to switch from a noncompetitive fuel—oil—to a more competitive one.

Such an opportunity did present itself in the form of waste wood. NSP had available to it a large supply of wood in the area. Southwestern Wisconsin is covered with small lots of hardwood that serve a large forest products industry, notes Schuster. NSP had an opportunity to use that waste wood and began looking at ways to burn it. Fluidized bed combustion was the chosen alternative. The technology was a familiar one in the area because the forest products industry had been using it for a number of years on a small scale to burn its own wastes.

NSP took four fluidized bed modules manufactured by firms that serve the forest products industry and set them in the base of the 1948 boiler to operate as a single bed. Ancillary equipment such as wood handling and flue gas treatment systems was also provided.

NSP experienced several problems in the early months of the unit's operation, but the difficulties were less integral to the fluidized bed itself and more related to the ancillary systems, notes Schuster.

"The fundamental problem we had with the fluid bed was learning how to start it up," he explains. "To begin with you have a cold bed of, in our case, fired clay, sitting there with a mass of many, many tons, and you want to eventually heat that mass of material to 1500 degrees Fahrenheit and have it fluffed up like popcorn. First you must heat it up with an external fire. Then you have to get a fire started in the boiler and carefully add the fluidized air without putting out the boiler fire or cooling off the bed. It took us a while to learn how to time those things."

Despite these problems, the plant's reliability improved each month and its forced outage rate dropped dramatically. Now NSP considers its French Island Unit 2 facility to be an economic plant again. "We're there," says Schuster. "To give you an example, on a mild day in September, NSP would have about six power plants on line: three 500-MW nuclear plants, two 700-MW pulverized coal plants, one 190-MW coal plant and the 14-MW French Island plant. It's next in the economic dispatch schedule. This is what we wanted to achieve."

NSP also had another motivation behind its involvement in fluidized bed at French Island, however. The utility wanted to gain experience with the process on a small scale that would be valuable in future, larger fluidized bed efforts. Explains Schuster:

"We see in the future that the day is going to come when we will be operating fluidized beds in large coal-fired facilities, not as research projects, but purely as power generation facilities. We see that coming and we really don't want to get there with no experience. So we said that here at French Island we can do two things at the same time: imgram there to verify the operability of the pressurized fluidized bed combustion systems proposed for the 170-MW demonstration plant. AEP, SL, and DBA are also performing the detailed design of the 170-MW demonstration plant and the preliminary design of a commercial unit that would have a size of about 650 MW. The goal for the commercial design work is to assess the economic attractiveness of the commercial version of the technology.

If the test program at the Swedish test facility is successful and if the engineering and cost estimates show that the technology is attractive relative to conventional technology, AEP will then be in a position to decide whether or not to proceed with the demonstration plant. A positive decision could have the demonstration plant operable before the end of this decade, says Jim Markowsky, manager of Analytical and R&D for AEP. The earliest that the commercial version of the technology could be built and operated would be in the mid-1990s.

However, the reality of building the demonstration plant will depend on the availability of adequate funding, Markowsky explains. In the current financial environment, AEP sees little chance of being able to fund the construction of the demonstration plant on its own. Although officials are enthusiastic about pressurized fluidized bed combustion combined cycles from a technological standpoint and believe that the work in progress will show the technology to be promising, they admit that the financial aspect of going ahead with a demonstration plant is very uncertain at this time.

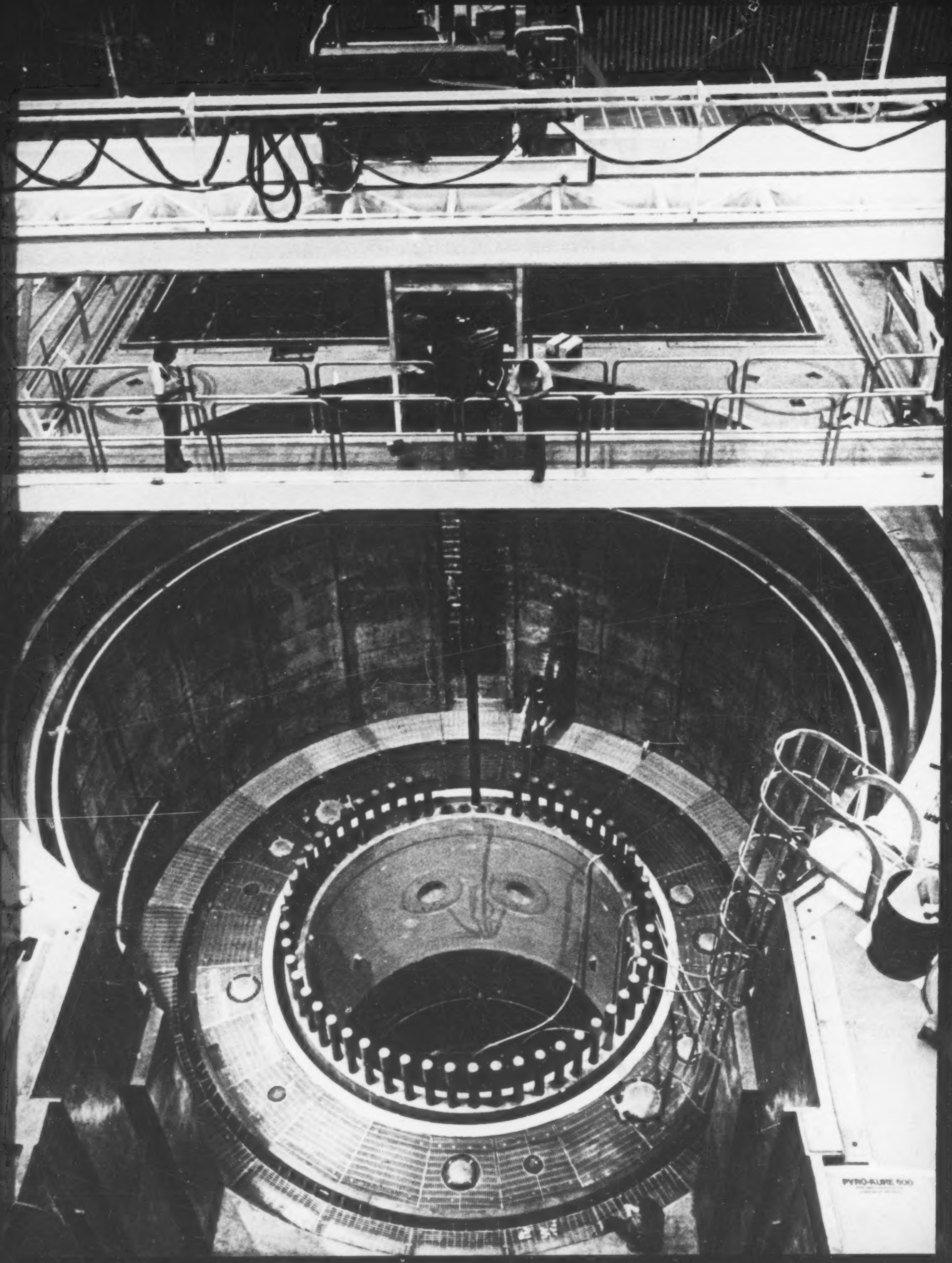
As efforts continue, however, and as progress is made in each of these research fronts, it becomes more and more likely that utilities will have the opportunity in the foreseeable future to choose among various types of fluidized bed combustion boilers for coal-burning power plants. As uncertainties are resolved about each of these boilers, it will be possible for utilities to take advantage of this "better way to burn coal" in the 1990s.

prove an old boiler's economic efficiency and build within the company a stockpile of experience with handling fluid beds."

NSP is doing more than just envisioning this prospect for the future. The company is now in the conceptual engineering stage of a project which would modify an existing 125-MW coal boiler at its Black Dog plant in Minnesota to accommodate a fluidized bed boiler that would burn coal and generate electricity for customers. This is one of the projects that EPRI is considering as part of its program to support a 100- to 200-MW commercial atmospheric fluidized bed combustion demonstration facility.

In the meantime, NSP and EPRI have begun a program at French Island to test the use of a variety of fuels in the fluidized bed boiler there. During the next year the two organizations will be conducting tests co-firing wood with such fuels as peat (widely available in the area), processed railroad ties (which have presented disposal problems), shredded rubber tires, agricultural wastes, and refuse-derived fuel.

"We are intellectually and emotionally committed to fluidized bed and we're cautiously committing money to it," explains Schuster, summing up the utility's interest in the technology. "We are trying to stagger our monetary commitment to reflect the experience we get as we go along. Our French Island experience has been a positive one, and therefore we're going a little step further and putting a little more money into it."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Ancient Glass and the Safe Disposal of Nuclear Waste

By Maureen F. Kaplan and John E. Mendel

3500-year-old glass artifacts allow nuclear scientists to peer thousands of years into the future

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The safe disposal of nuclear waste is naturally of great interest to both the general public and the scientific community. There have been many years of laboratory research on the subject, but what is little known is that archaeology—traditionally the science of the past—may play a unique role by placing some of the issues in perspective.

This story concerns a particular type of nuclear waste. Nuclear reactors for commercial power use enriched uranium as a fuel. When a certain amount of uranium-235 has been split (or fissioned), the fuel can no longer support the reaction and it is considered "spent fuel." Every 1,000 kilograms of spent fuel, however, still contain roughly 950 kilograms of uranium and nine kilograms of plutonium which could be recycled for fuel. Even if no new reactors went into operation in the United States and the plants now existing have a 40-year lifetime, scientists figure that there will still be about 48,000 metric tons of spent fuel to be disposed of.

This "spent fuel" obviously contains a large amount of fuel that could be reused. If recycling does take place (no recycling of commercial spent fuel has yet been done in the United States) what remains is "high-level waste (HLW)"—a mixture of many isotopes with varying half-lives (from a few days to iodine-129 with a half-life of 16 million years) and toxicity. This is highly radioactive and must be isolated from the public.

But for how long? Opinions vary. The National Academy of Sciences suggests 600 years; others say 250,000 years (i.e., ten half-lives of plutonium-239). The estimates range widely because high-level waste is a highly varied mixture of many isotopes. One way of looking at the problem involves comparing the hazards of HLW with that of the ore from which it originally came. If the comparison considers the ways different isotopes build up or are diluted in the biosphere, the hazards from both spent fuel and high-level waste are roughly comparable to those of an equivalent ore body after 10,000 years.

How can this be done? Several ways have been suggested for getting rid of high-level waste including burying it beneath the Antarctic or shooting it into space. The one idea that has received the most study is burying it deep within the earth, at least 1,500 to 1,800 feet. Actually, the disposal of highly radioactive wastes involves something called the "multi-barrier concept"—that is, the barriers between the waste and people will be so numerous that the overall safety of the design will not be compromised if any one of them fails. The barriers under consideration include, but are not limited to:

- Remote location.
- Location where geologic events and processes cannot harm the burial system (volcanoes, earthquakes, erosion, etc.).
- Suitable rock. Shale, tuff, salt, granite, and basalt are under consideration.
- Well-designed plugs and seals for mine tunnels and shafts.
- Material that absorbs and holds up radioactive ions from transport in groundwater. This can be the rock itself, backfill in the tunnels and shafts, material packed around each container, or all of these.
- Long-lived containers.
- Waste prepared in a stable and corrosion-resistant form.

Under such a design, the only potential pathway for the radionuclide materials to reach humans is for groundwater to traverse all of these barriers and then go back toward the environment.

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Each of these barriers is being designed, for the most part, by different teams of researchers. Each team prefers to consider its barrier the most important in terms of safety. These material scientists, however, are used to working in rapidly changing fields and looking at an unpredictable future. The talk of designing a system to last, say, for 10,000 years can appear daunting. The archaeologist, on the other hand, routinely works with man-made objects and materials which have already survived for thousands of years. It is this perspective which is generally missing from the studies on nuclear waste disposal.

Scientists are now leaning toward using a material that archaeologists know well—glass.

To return to the multi-barrier concept, the center is a stable waste form. A number of candidate substances will probably not be considered for the final design for various reasons. Dried high-level waste is a powder which spreads too easily in case of a transportation accident. Crystalline forms involve complex processes in manufacture, and a consistently good product may be difficult to obtain. Scientists are now leaning toward using a material that archaeologists know well—glass.

One of the main reasons for considering glass is its blend of stability and intrinsic resistence to radiation damage. Many solids get their precise shape from symmetrical or crystalline arrangements of three-dimensional atom networks. But glass is in reality not a solid but a liquid made up of asymmetrical, non-crystalline networks, formed in the happenstance of the material's melting and cooling. This means that while glass has hardness and shape, it has no set chemical pattern or structure—a fact of enormous significance for nuclear waste material.

Normally, the radioactive alpha and smaller beta particles thrown off by decaying isotopes (such as uranium and plutonium) will knock atoms in the structure of any solid out of alignment. The effect, by knocking electrons off atoms like bolts off an Erector set, is eventually to distort the structure of the substance and make it more corrodible. In archaeology, thermoluminescence is a means of measuring an object's altered electron energy from extended exposure to radioactive elements in nature. The amount of this stored radiation released through heating thus reveals the object's age—in reality the extent of its structural deterioration. Yet it is impossible to get thermoluminescence dates from ancient glass for a simple but for nuclear waste disposal the most important reason. True glass is unlikely to be structurally altered by radiation because it has no crystalline pattern in its molecular structure in the first place.

Glass is, of course, a mixture of solids to begin with: silicate, usually from a sand base; modifiers such as sodium and potassium (in antiquity often derived from natron and wood ash); and stabilizing compounds, generally lime or magnesium in antiquity. Because each of these three ingredients—formers, modifiers and stabilizers—can be fashioned from a number of substances, scientists have considerable leeway in perfecting glasses that might chemically immobilize radioactivity. Today, nuclear chemists are working on a boron rather than a sodium or potassium modifier because that ingredient allows glass to be melted at lower temperatures, minimizing the amount of volatile radioactive isotopes driven off as gases.

With so much of the potential inner radiation damage taken care of, the main issue will be its ability to resist weathering. Scientists think they have alleviated part of this problem by proposing that nuclear waste glass be formed in cylinders roughly ten feet high and one foot in diamter. With such a high volume to surface area ratio, only a minimal outer area would be exposed to weathering. This step alone should produce drastically different rates of corrosion from those found on the relatively huge surface areas of window panes, goblets and almost all other known glass objects.

Nonetheless, scientists are still trying to devise every conceivable test to find out just how the waste glass will respond to millennia of weathering. Borosilicate glasses are being ground down and flooded with water under high pressure, bombarded with radioactive alpha and beta particles, buried and dug up, and pushed through enormous temperature extremes. These severe tests are meant to accelerate reactions artificially under milder conditions but for very long periods of time, so that scientists can peer not generations but thousands of years into the future. Without a time machine, laboratory simulations have naturally seemed to be the only way to get at such a vast period.

At least such was the case until recently when nuclear scientists realized that archaeology can speak of just such a time frame with ancient glass. Although they were by no means designed to last as long as "nuclear" glass, intact glass objects have been dated as 3,500 years old from the well-established dates of their burial sites. Although these early soda-lime glasses differ chemically from the borosilicates, they can provide important models for the aging process and the potential damage it can do to nuclear waste glass. Battelle Pacific Northwest Laboratory, which is developing borosilicate glass for the disposal of high-level waste, sponsored a project in 1979 to summarize the information available on archaeological glasses and their weathering.

Archaeological evidence shows that five main types of glass decomposition and weathering can be identified—weeping, crizzling, pitting, layering, and crusting. All amount to a leaching out from the surface of essential ingredients. But a significant point gained from the project is that many of these processes are less a function of age than of the glasses' own chemical composition and external environment. It is interesting, for example, that some of the most deteriorated ancient glass is of relatively recent or Mediaeval origin.

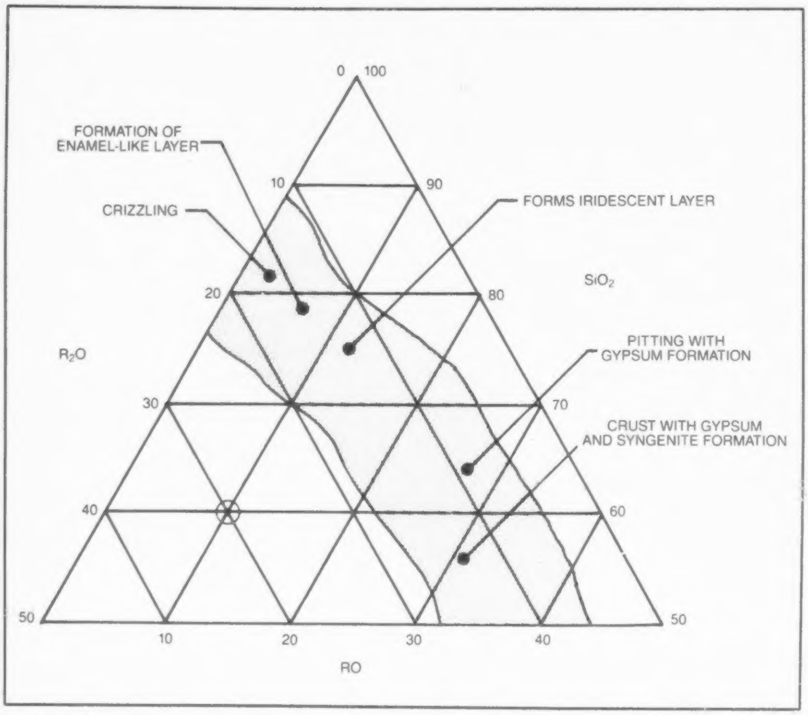
As a result, certain forms of instabilities such as weeping—the sweating of droplets of water when excavated glasses come into contact with moisture in the air—can be found on Renaissance and Baroque goblets. Another chemically related process is crizzling—the formation of networks of tiny cracks all over an object's surface. Crizzling is directly related to weeping, and is a leaching out of water and chemicals from within until the glass surface dries out like a mudflat and cracks. In its worst stages, it does so into a mass of loose, opaque flakes that make conservation extremely difficult. At this stage, however, the networks of cracks generally do not penetrate all the way through the walls of the object.

Ancient Mediterranean and Near Eastern glasses undergo a process called layering that leaves them with a filmy iridescent surface. Until late-nineteenth-century investigators found discrete mica-like layers from 0.3 to 15 micrometers thick within these unusual surfaces, the iridescence was mistaken for the product of some lost decorative technique, and was not seen as a weathering effect at all. Actually another leaching process, layering involves a slower and less complete chemical breakdown, or filming over of the glass surface. The iridescence is caused by refraction of light between layers. Even finer distinctions in layering can be made—"Persian" glass, for example, forms enamel-like films while material from Europe is often more flaky. In contrast to crizzling, the formation of silica layers may have a protective buffering effect on the inner integrity of the ancient glass. This aspect of possible glass corrosion is presently under investigation by material scientists.

Archaeological evidence shows that five main types of glass decomposition and weathering can be identified. . . .

Another process that ancient glass undergoes is pitting, which can occur in two ways. One type of pitting is the gouging, pothole-like effect on glass objects—an abrasive surface interaction that can potentially expose a big lump of internal trace elements or outer layer remnants. A second type of pitting, which occurs only in potassium-lime Mediaeval stained glass windows, involves a complete chemical dissolution of the silica base of the glass. The actual scar or pit often contains clumps of weathering products like gypsum.

Unlike the thin film of layering, surface crusts are generally powdery. These amorphous and opaque residues are formed by the leaching of chemicals out of the glass in a way that alters an object's whole structural stability. This process, again restricted to Mediaeval windows, disintegrates or drains out the silica base itself; when complete, it is as if nothing is there. It is safe to say that had such structurally deficient Mediaeval stained glasses been formed, for example, in the second century after Christ, not one would be left today—a fact that deeply concerns European countries interested in preserving these often beautiful objects for generations to come. Fortunately, such concern has recently sparked new studies on the chemistry of glass weathering that may not only help in conservation, but may also provide valuable information in the search for a safe means of disposing of nuclear wastes.



Triangular diagram showing glass composition. Glass formers (usually silica) are marked by SiO_2, network modifiers (sodium and/or potassium) are marked by R_2O, and RO represents network stabilizers (e.g., lime). The asterisk marks a glass with a composition of 60 percent silica, 30 percent sodium and ten percent lime. The shaded area represents the compositions used in ancient glasses. Different types of weathering associated with various glass compositions are indicated.

The study sponsored by Battelle Laboratory also attempted to correlate the types of weathering with changes in the chemical composition of the glass. It appears that the most devastating processes—crizzling and crust formation—correlate with too little or too much lime, respectively, in the glass for good stability. In this regard, archaeology can point out the compositions to be avoided in nuclear waste glasses.

The work on archaeological glasses may also affect some theories on how glass corrodes. At this point, there are two main theoretical models for estimating how glass will weather. One assumes that glass is rapidly corroded by the leaching of selective ingredients —at first, alkalis such as sodium and potassium—to the surface. The other assumes a slower "network-dissolution" or total chemical breakdown of the glass. Another related argument says that the short-term corrosion is governed by the first mechanism while the long-term corrosion is governed by the second. But the archaeological evidence indicates that complete network dissolution may only occur for some glass compositions but certainly not all of them, for such complete dissolution is really only observed in Mediaeval glass. More ancient glasses frequently do have extensive weathering layers, but even after 3,000 years, the original surface is often still intact. Given the proportionately greater surface area of ancient glasses, such remarkable survival rates may bode well for the disposal of nuclear wastes—especially when one remembers that the more chemically sophisticated new waste glass cylinders will also have a far more limited surface area, and thus drastically reduced vulnerability to aging.

This point is worthy of emphasis. Aside from the teams of researchers designing each barrier, groups of people are studying how all these barriers interact by building computer models of their behavior. While the material scientists may give conservative estimates of how their barriers may perform, the modelers sometimes further reduce these estimates for their analysis of the safety of the disposal system design. Some safety analyses assume that the large glass cylinders completely dissolve in one thousand years. It is obvious just how conservative some of these safety analyses have been when one considers glass from antiquity—much smaller objects with much greater proportions of surface area available for weathering have survived more than three times longer.

One method of corroborating the information on ancient and nuclear waste glasses is to put samples of ancient glass through the same laboratory tests that have been performed on nuclear waste glasses. Gladys Weinberg of the University of Missouri donated samples of glass from excavations at Jalame in Israel for just such testing at Battelle Laboratory. The samples date to about A.D. 350–385 and some are in excellent condition.

Another important point illuminated by archaeology is that not only internal chemical composition, but also the outer environment affects the survival of glass. Archaeologists know, for example, that while Roman glass is all basically homogeneous in composition, its survival and resistance to corrosion is clearly dependent on *where* in the huge empire it was abandoned. Most of Roman Europe had a highly fluctuating environment with annual extremes of moisture and temperature, freezing and thawing. But Mesopotamia, the Middle East and most of the Mediterranean have only a mildly fluctuating climate, and Roman Egypt and other desert areas are nearly always constant.

Ancient glass generally shows what it has been through. Glass objects from graves in Roman Europe, for example, are often so decayed that only the surrounding soil keeps them together. The objects are too fragmentary, sometimes powdery, to be moved, and excavation is often possible only by removing the whole block of soil and glass for laboratory work.

If freed from the annual freeze-thaw cycle, glass fares much better. Material excavated in the Middle East and similar regions usually shows some weathering effects, but fragments and vessels can be removed from the soil without prior consolidation. Moreover, many objects do not show any weathering at all upon excavation, although iridescent flaking layers often develop a short time afterward. Finally, glass artifacts recovered from arid areas like Egypt are frequently spectacularly well preserved.

The point is that the environment of an object—whether it is an archaeological object or cyclinder of nuclear waste—is a key to its resistance or vulnerability to corrosion. Buried hundreds of feet under the earth, the nuclear waste and its protective canister will undergo no extreme changes in temperature and humidity, nor will they be subjected to freezing. The material will be exposed to radiation and heat from the nuclear waste itself; these conditions—which can be at least partially counterbalanced—will cause no sudden environmental extremes by themselves, and should diminish gradually and evenly over a long period of time. When all these factors are added up, it becomes apparent that *many ancient glasses in all likelihood have already survived more destructive environments than will be found in the climateless deep underground.* This suggests that the nuclear waste glasses should age slowly and safely.

Unexpected bedfellows, archaeologists and nuclear scientists are just beginning to work together, but already common tests are being set up for both well-documented samples of ancient glass and experimental nuclear waste glasses. So far, scientists have not been able to turn all the disparate findings on modern glass into any universally agreed upon projection of the material's ultimate survival. But the very existence of 3,500-year-old glass, which was not designed for long-term durability, but for beauty, can provide a comforting perspective for those who are designing such glasses for the disposal of highly radioactive wastes.

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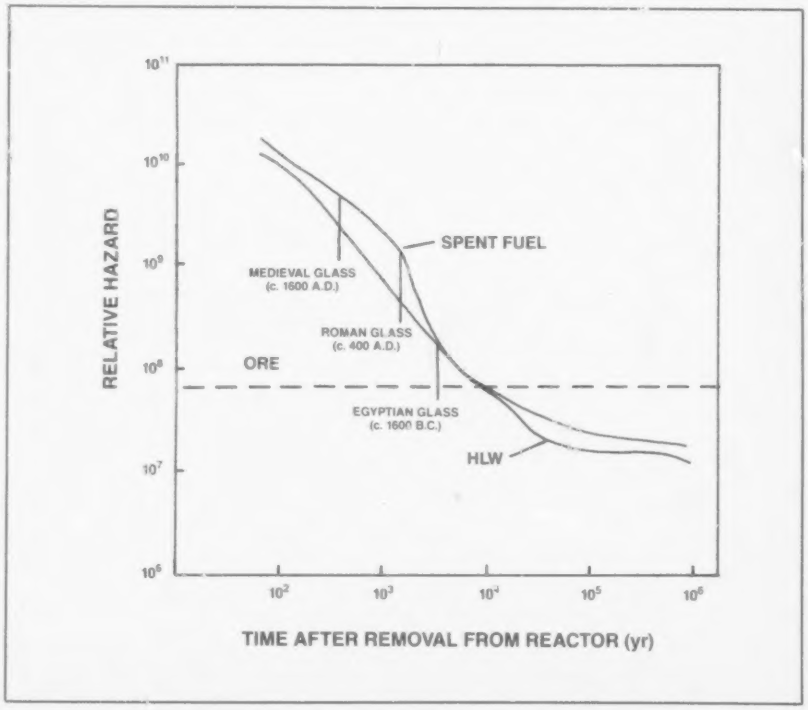
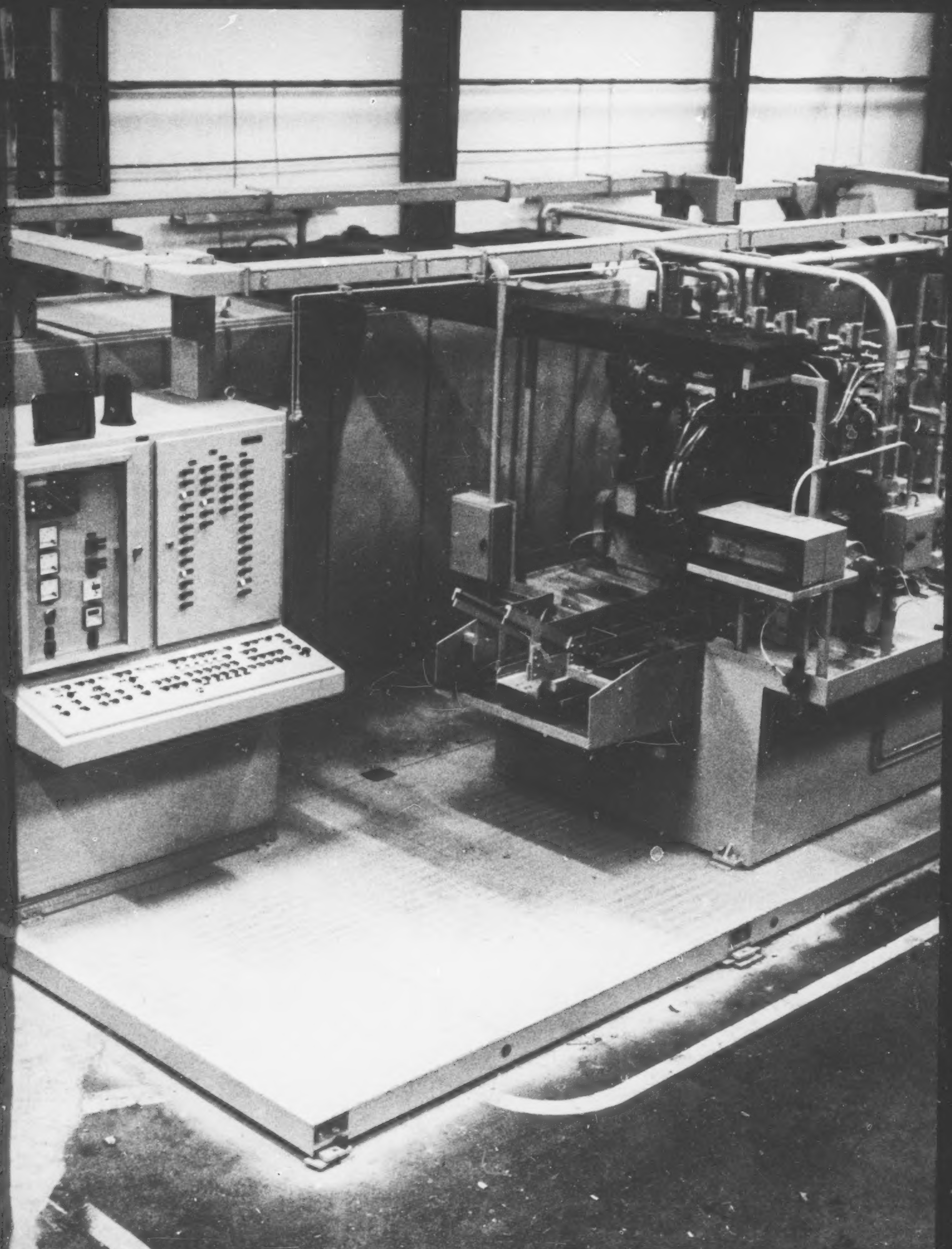


A graph showing the relative hazards of unreprocessed spent fuel, high-level waste (HLW) from reprocessing and a comparable uranium ore body, along with the ages of various ancient glasses. If the buried waste form lasts no longer than Egyptian glass which has already survived, both types of nuclear waste have decayed to where they are only twice as hazardous as the ore from which they were mined. It should be noted that the relative hazard does not include other factors such as depth of burial (the wastes will be deeper than most ore bodies), long-lasting containers and other engineered barriers.



Neoindustrialization: The New Technologies

By Mary H. Wayne

Innovative production technologies use electricity to unlock some of the shackles constraining industrial productivity growth

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This is the second of a three-part series on "neoindustrialization." Part 1 reviewed why *changes in industry's methods of production are needed now, just as they were needed at the dawn of the Industrial Revolution, to boost productivity. Part 2 examines* how *innovative electricity-based technologies can spark productivity growth. Part 3 will consider* what *these changes may mean to society at large.*

American industry faces a double bind: a shrinking, increasingly expensive resource base and escalating costs in almost every other area as well. Such conditions sap productivity. Is there a single remedy for these twin ills? History suggests that there is. That remedy is technological innovation.[1]

Historically, changes in the resource base of production have sparked changes in production methods themselves. When in 1709 Abraham Darby first developed his method for smelting iron using coal instead of charcoal, it was in response to England's shrinking supplies of wood. The island's forests had been squandered in inefficient charcoal smelting and in a fever of shipbuilding to seek out the world's deposits of gold and silver. By Darby's time, Britain was in the throes of an energy crisis. The ironmonger's contribution was to find a new way to smelt ores that bypassed the need for wood.

Several historians point to Darby's invention as the starting signal for the Industrial Revolution. Until then burning wood and charcoal and human and draft-animal labor had powered most industries, for the heavy fumes that rose from burning coal damaged many products. In the early eighteenth century, however, new methods, such as Darby's, were devised to avoid this problem and to take advantage of the fact that a chunk of coal contains considerably more energy than a piece of wood the same size. New coal-based technologies sprang up across Europe, slowly transforming one industry after another. The coal-burning steam engine revolutionized not only industry but transportation, especially in the New World, where steamboats traversing America's rivers and steam locomotives pulling railroad trains across its vast plains helped consolidate a new nation.

These coal-based technologies sidestepped the need for a scarce resource. What's more, they eventually reduced the total costs of producing everything from metal machine tools to cotton garments. These two features—the use of new resources in production and the ability to cut production costs—have come to be historic hallmarks of technological innovation.

The Nature of Innovation

According to consultant Charles A. Berg, the word *innovation* in an industrial context has a very precise meaning.[2] It does not mean any method that is simply novel or unusual. Nor does it mean any method that happens to cut costs. It means a method that is inherently less costly than its predecessor because it cuts or eliminates outright certain costs that are intrinsic to the old process.

Berg calls these intrinsic costs "irreducible costs." They are the minimum

At its Saginaw Steering Gear Division, General Motors recently installed this induction machine to harden front-wheel-drive axle shafts.

Mary H. Wayne, a free-lance writer based in San Francisco, specializes in energy issues.

. . . the real test of an innovation's economic superiority is its ability to cut the total production bill. . . .

requirements of natural resources, time, and all other factors of production associated with the implementation of any particular production method. These requirements have to be met even if the method is executed with maximum efficiency—that is, to complete perfection. They define the limits below which factor costs can be reduced no further.

An example of innovation from recent history is Pilkington's invention in 1954 of the float process in glass making. Before this innovation, large pieces of flat glass had been produced by a laborious three-step process of casting, grinding, and polishing plate glass. The float process eliminated the grinding step—and its irreducible costs—entirely. Instead, it floated molten glass directly on a sea of molten metal, where the glass solidified to form a continuous sheet that was already flat and needed no grinding to assume the proper smoothness.

The float glass method made large pieces of glass much cheaper to produce, and so altered the face of the nation's cities. Before Pilkington's innovation, glass in large sections was so expensive that it was reserved for use in commercial display windows. Now it clads many of our newer skyscrapers.

Just as Darby's smelting process eliminated the need for a scarce resource, Pilkington's float process eliminated the need for a labor-intensive operation. Both circumvented an irreducible cost of the old method. So both qualify as technological innovations.

In contrast, many cost-cutting moves fall outside this definition because they simply refine an existing process. Typically, those who adopt an innovation soon find ways to make the product cheaper, faster, and better by improving the basic method. These refinements may be made year after year. For example, the number of U.S. patents for improvements on the ancient and venerable horseshoe peaked only in the second decade of this century, just when the horse was replaced as transportation by the automobile.

The advent of a competing method can stimulate a temporary rash of improvements in the old way of doing things. Historian D. S. Landes has labeled this phenomenon the "Indian summer" of an obsolete technology. The open-hearth method of steel making had its finest hour immediately after the innovative oxygen steel making process first appeared on the industrial scene. But the inherently more efficient oxygen process replaced even the improved open hearth technology because it could avoid some of the built-in costs of the old method.

Berg observes that whenever an innovation succeeds in reducing one previously irreducible cost, reductions in all other costs of production tend to follow. Such progress is often ragged, however. Total production costs may fall right away when an innovation is introduced, but some components will typically lag others. Some costs may even rise temporarily, as in the case of a new process that requires more highly trained labor or parts that are not yet widely available. These cost bulges in individual components tend to smooth out over time. In the meanwhile, the real test of an innovation's economic superiority is its ability to cut the total production bill, even over the short term.

Cutting production costs means boosting productivity. Total factor productivity is simply the ratio of output to all the combined inputs in the manufacturing process—not only labor, but raw materials, capital, energy, and all the rest. If the sum of these inputs can be shaved while output remains constant or rises, then overall productivity will rise. The point is always to get the most output per unit input, or, in other words, to get the product out at the lowest total cost to the manufacturer.

Historical patterns of innovation bear directly on the recent productivity bog of U.S. industry. First, industry faces shifts in the resource base available for production. The oil and natural gas fuel supplies used for decades to fire the nation's expanding industries are slowly dwindling away, and becoming more expensive as they go. What's more, many of the critical raw materials used in industry are largely under foreign control and subject to arbitrary price increases, just as oil is.[3] So industry has a multiple problem in the resource area. Add to this resource picture the escalating costs of land, labor, capital, and all the other basic factors of production, and we have an industrial system ripe for—and desperately in need of—innovation.

Innovation and Electrical Energy

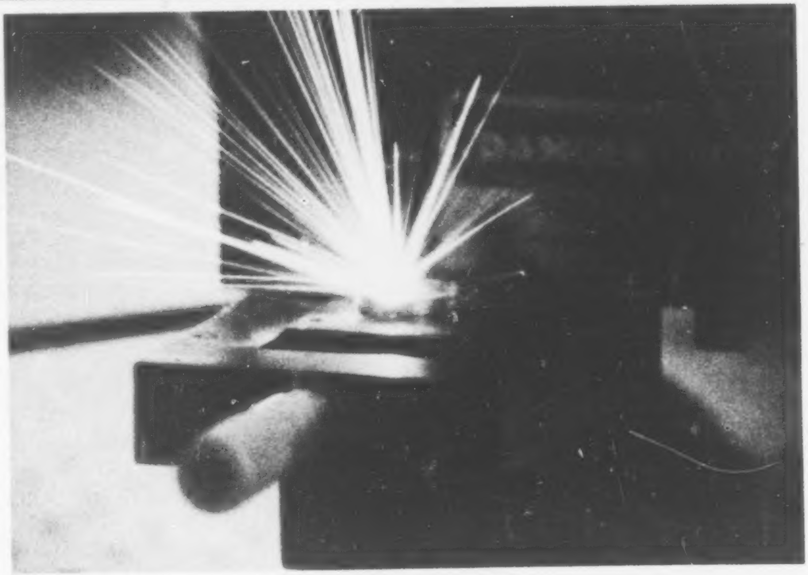
One of the most promising possibilities on the current industrial horizon is the trend toward use of electricity rather than direct fuel combustion to drive industrial processes. Electricity-based technologies can first ease the fuel bind by substituting electricity made from abundant domestic resources, like coal, for less abundant gas and oil fuels. (Burning coal directly for industrial use is unsuitable for many processes that require a clean energy source.) In addition, electrical production methods can sometimes substitute domestic raw materials for expensive imports. And they very often reduce other production costs as well. Land, labor, and capital costs, including environmental control costs, may all be shaved when an electrical technology replaces one that is combustion-based.

At first glance, the idea that electricity-based processes can cut industrial production costs may seem a paradox. After all, electricity costs more than oil or gas: about $15 per million Btu for the industrial consumer, as opposed to about $8 for oil and $4 for gas. How can industry save money by switching to a more expensive form of energy?

The answer lies in the unique properties of electrical energy. These properties allow it to function in ways that other energy sources cannot.[4]

For a start, electrical energy is more highly organized than heat energy. Its form allows it to be channeled instantly and directly into useful work—heating the filament of a light bulb, moving the rotor of an electrical engine, or, more recently, powering a wave of electronic inventions ranging from the home computer to the worldwide telecommunications network. When work energy is derived from burning fuel, in contrast, some heat energy is always lost to the atmosphere. Consequently, electrical energy is more efficient than other energy forms for many tasks.

It can also be controlled with unmatched precision. Focusing the heat energy liberated by fuel combustion can be awkward and difficult, especially if the target area is small. With electricity, it is easy. Energy can be applied at precise points, in precise amounts, for precise periods of time. The new electrical laser techniques being used for everything from microsurgery on the human eye to inscribing delicate computer parts exemplify this precision.



In 250 millionths of a second, this high-powered laser beam drills a hole 1 thousandth of a millimeter in diameter through a stainless steel part. The blast effect creates a shower of molten steel particles.

Electricity can provide more intense energy, too. At its best, fuel combustion provides heat no greater than about 5000 degrees Fahrenheit and that is only with the purest hydrogen fuels. Electric heating processes can double this intensity, to around 10,000 degrees Fahrenheit or higher. In industry, this high temperature capability can be the key to saving a great deal of time and money on the production line.

In addition, electrical process systems offer a kind of flexibility that combustion systems typically do not. Electrical equipment can run on power made from any number of energy resources, whereas a combustion system is usually geared to the use of one fuel and no other. Another flexible feature is that electrical systems are often smaller and less space-consuming than their combustion counterparts, partly because there is no need for areas in which to store and handle fuel. And electrical systems can operate wherever there is electric power, instead of requiring a location near the pipelines or railroad lines that carry fossil fuels.

Finally, electrical systems are cleaner to operate. There are no fumes or smoke to affect the workers, the environment, or the materials being processed. Electricity-based technologies relieve industry of considerable responsibility and cost associated with the need for worker and environmental protection.

Electricity, then, has special advantages for industry. Its highly organized character gives it efficiency, controllability, and intensity that are all unique among energy forms. What's more, electricity-based systems are flexible and clean, reducing or eliminating many logistical and environmental problems that make plant siting more difficult for combustion-based systems. These advantages, taken together, can outweigh the higher price of electricity. When all the requirements of a manufacturing process are considered, electricity—though more expensive per Btu than oil, gas, or coal—is often the most economical choice as a process energy base.

Combustion heating relying on high quality fuels . . . often uses them inefficiently.

Combustion Technology: A Baseline

Applying the unique advantages of electricity to the manufacturing process may hold the key to increased productivity in many industries. The point is to do more with less—less energy, less time, less labor, less equipment, and so on. A look at conventional combustion technology can provide a baseline for comparison.

Many important industrial processes such as steel forming and glass making have two characteristics in common, Berg points out.[5] Each must be carried out at high temperatures, in excess of 2000 degrees Fahrenheit. And each is chemically sensitive, requiring an energy source that is reasonably free of contamination. These two needs are related, by the way, since contaminants do their worst damage at high temperatures.

Natural gas, called by some the prince of hydrocarbons, has been the fuel of choice in such processes for many years. But restricted availability and rising prices in the past decade have forced some manufacturers to consider other options. Low-sulfur oil is one candidate. The same questions of availability and price apply to this fuel, however. Substituting oil for natural gas is at best a short-term expedient. Something more basic is required to assure production continuity well into the future.

Consider the steel industry. Before pieces of raw steel can be turned into finished products, they must be reheated to a sufficiently high temperature (about 2350 degrees Fahrenheit) to make them malleable for forging and forming. Combustion reheating relying on high quality fossil fuels not only uses fuels that are becoming increasingly scarce and expensive, it often uses them inefficiently.

Berg cites the case of a small reheating furnace, known descriptively as a slot furnace due to the shape of its door.[6] Before any modification, this furnace required 35 gallons of low-sulfur distillate oil per hour to heat 1500 pounds of steel per hour from 80 to about 2400 degrees Fahrenheit. When a complete set of conservation features was installed, including recirculating burners, fuel consumption was cut to 22 gallons per hour. This very substantial improvement was the result of applying the most advanced techniques available for combustion reheating to the operation of the slot furnace.

But how efficient was the furnace even after these modifications? Though the furnace was actually busy reheating steel for only 8.6 hours of the day, the furnace burners had to be kept on at various levels of output for the entire 24-hour day. An industrial combustion furnace cannot just be shut off when it is not in use. Rapid cooling could damage the expensive refractory panels that line its walls. Furthermore, long lead times and large amounts of fuel would be required to warm it up again. So it must idle along, burning expensive fuel, even when it is producing nothing.

According to Berg's calculations, the resulting net efficiency of the unmodified slot furnace was 5.96 percent when viewed over a 24-hour day. In other words, only 5.96 percent of the heat released by combustion actually found its way into the stock being processed. The modified furnace, with all the newest conservation features, was a better performer, turning in a net daily efficiency of 9.34 percent.

Even this improved performance is not impressive. "Contrary to . . . popular opinion," Berg comments, "it is extremely difficult and costly to build high temperature combustion heating furnaces that exhibit high efficiencies of heat transfer." When it comes to combustion heating, he concludes, "high temperature operation and high efficiency seldom go together."[7]

An additional drawback of combustion heating that is linked to the need for continuous furnace operation is the difficulty and cost of performing routine maintenance. To allow workers to clean the furnace and replace worn out parts, the unit must be cooled down close to room temperature. The cooling can take as long as 300 hours, according to Berg, for a large furnace. Heating it up again once the maintenance is completed may take another 300 hours. And the maintenance itself adds more time to the total.

The result is weeks or even months of lost production. Given the economic loss that this implies, the upshot is that damage must often reach a fairly high level before management can justify taking a combustion unit out of production for maintenance. Yet, it is precisely such maintenance that keeps the unit running at peak performance.

For example, thermal stress can crack the mortar between the ceramic bricks in the furnace walls. Unrepaired, these cracks allow air to circulate into and out of the furnace, making it very difficult to control the combustion rate on which efficient fuel use depends. So the difficulty of maintaining combustion furnaces compounds the problem of low efficiency.

Another aspect of the maintenance dilemma is the frequency with which certain critical parts, such as conveyors made of expensive metal alloys, wear out. A major cause is the continuous exposure to high temperatures. So the maintenance problem grows. The need for round-the-clock firing of combustion furnaces not only consumes fuel, it consumes equipment as well.

And then there is the problem of oxide scale. A major drain on the overall productivity of the conventional steel reheating process is the effect of the combustion atmosphere on the steel itself. The presence of oxygen in the furnace's reheating chamber leads to oxidation of the stock being processed. The result is the conversion of a significant fraction of the stock to oxide scale, which is of no practical value unless it is recycled to a blast furnace or other reducing unit. If not recycled, it must be disposed of in compliance with environmental regulations, which imposes further costs. In either case, the scale represents a serious loss of valuable steel stock during the reheating process.

Exactly how much of the stock is lost to scale varies according to the particular furnace and type of operation. The range for combustion steel reheating is about 1 to 4 percent. The percentage may sound small, but the dollar losses are enormous.

The need for round-the-clock firing of combustion furnaces not only consumes fuel, it consumes equipment as well.

Berg cites the example of a small reheating furnace that processes about 15 tons of stainless steel per hour.[8] Stainless steel production plants typically produce for 2 shifts a day, 5 days a week, 50 weeks per year. If a single reheating step converts roughly 2.5 to 3 percent of the stock to oxide scale, then the furnace may produce as much as 1800 tons of oxide scale a year. And if the value of the stainless steel that leaves the furnace is $1.50 per pound, then the portion that has turned to scale represents a loss of some $5.4 million a year.

Looking at an annual loss of this magnitude from one small furnace gives some idea of the impact on the steel industry as a whole. The United States produces about 150 million tons of steel a year. Losing 4 percent of this output to scale during processing can mean industry losses of some $1.6 billion a year. Moreover, scale losses cost the industry not only in lost product but also in reheating fuels. Berg notes that scale losses are large enough to equal the profits of many firms in the industry.[9]

Typical of many U.S. manufacturers, steel makers have been struggling with low productivity and sagging profits for some time now. During the late 1970s, efforts to improve existing production methods focused on the then-current natural gas shortage and on the continuing need to upgrade the heat transfer capability of combustion heating equipment. A two-pronged strategy suggested itself. The idea was to substitute gas made from coal for natural gas and to feed this coal-based synfuel into redesigned, more efficient combustion furnaces.

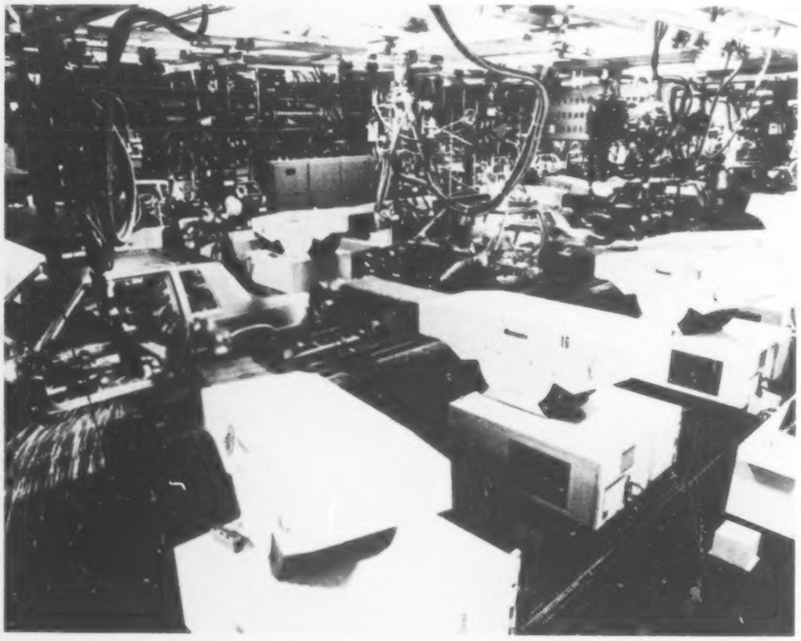
But a number of snags appeared in this approach with the advent of the

1980s. Not the least of them were the problems of comparative cost and environmental impact that stalled synfuels development in general and coal gasification in particular. Furthermore, the immediate natural gas shortage eased. And there were even more basic problems in trying to improve the net energy efficiency of combustion heating equipment, regardless of the type of fuel used to feed it.

Electric reheating and melting technologies . . . can help reduce the otherwise irreducible costs that attend combustion-based operations.

A study by Arthur D. Little, Inc., has estimated that present reheating furnaces, without heat recovery systems, operate at average net efficiencies of only about 5 percent. This means that combustion reheating can transfer only about 5 percent of the heat released by burning the fuel into the steel or other material being processed. The same furnaces could operate at efficiencies of roughly 20 percent if heat recovery apparatus were installed, according to the study.[10] Even this level, however, means that some 80 percent of the energy contained in the fuel is lost to the atmosphere.

What's more, efforts to improve conventional reheating technology have failed to address some of the other drawbacks already mentioned. Substantial scale formation is an inescapable feature of combustion reheating. So are the maintenance problems of a system that cannot be turned on and off at will. Combining coal gasification with upgraded furnace systems could indeed permit continued use of combustion reheating, but it does not offer an especially efficient use of energy, nor does it relieve some traditional drains on the productivity of the steel industry.



With uniformity of spot location and weld integrity, robots spot weld cars and trucks for almost every vehicle manufacturer in the world.

Electrical Steel Processing

Are there other choices? Yes, particularly in the area of electricity-based processes. Electric reheating and melting technologies, plus a new method for separating the iron from its ore, are examples of the innovative processes that can help reduce the otherwise irreducible costs that attend combustion-based steel operations.

Philip S. Schmidt of the University of Texas has done extensive studies of electrical process technologies and their impact in different industries. He provides the following comparison of combustion and electrical reheating technology in the steel industry.[11] Schmidt's estimates are based on a 30,000-ton-per-year steel forging facility.

The alternatives in this scenario are a combustion furnace fired by natural gas and an electric furnace that relies on what is called induction heating. With induction heating, a steel billet is actually heated from the inside out rather than receiving heat transferred from contact with an external source. The billet, being metal, is electrically conductive. Placing it in a rapidly fluctuating magnetic field is enough to induce electric currents within the billet itself. These currents quickly heat the billet to a point suitable for forging.

This internal energy deposition, possible only with electricity, carries a number of advantages. Most important, electric induction reheating holds down the materials losses that are a major drawback of combustion systems. Heating a steel billet in a combustion furnace can cause not only scale formation but also surface cracking due to thermal stress. Internal heating eliminates a great deal of surface stress and, because of its speed, gives scale little time to form.

Schmidt estimates that a well-maintained gas furnace in a steel forging operation will lose about 2 percent of its steel throughput to scale. Another 1 percent of the heated product will have to be scrapped for cracking or other failure to meet quality standards. Using an electric induction furnace instead, he estimates, can cut these losses to 0.50 and 0.25 percent, respectively. Switching to electrical reheating, he concludes, can reduce the annual bill for materials loss from scale and scrappage in a 30,000-ton-per-year steel forging operation to about $150,000—to only a quarter of the roughly $600,000 that would otherwise be lost as an inherent production cost of combustion reheating.

Operation and maintenance are also more economical with the electrical unit. The electric induction furnace needs only one operator, whereas the gas-fired furnace usually needs two. Furthermore, the combustion furnace, which is intrinsically harder to service because of its state of continuous firing, requires twice as much maintenance to stay clean and in peak operating condition. The result, in Schmidt's estimate, is a $120,000 annual labor bill for operating and maintaining the gas furnace, and only half of that, or $60,000, for the electric furnace.

So both materials loss and maintenance costs are alleviated by a shift to electrical reheating. What about the third major problem with combustion reheating, its energy efficiency? How competitive is the electrical system in this respect?

To make a fair comparison, we must begin measuring the efficiency of the electrical process at the same point that the combustion process begins—with burning the fuel. The conversion of a fuel such as coal to electricity at the power plant operates at an efficiency of about 34 percent. In other words, about two-thirds of the energy in the coal is lost during its conversion to electricity. But this is only part of the story. What more than compensates for this conversion loss is the fact that once the energy is in electrical form, very high efficiencies of energy transfer from the induction furnace to the workstock can occur.

The current level of energy transfer in induction reheating of steel is in the range of 70 to 75 percent, according to Charles Berg.[12] The net energy efficiency of the entire electrical process, then, beginning with the coal and taking into account the energy losses that occur in generating and distributing the electricity, comes out to about 25 percent. This figure, though not spectacular, compares favorably with the 20 percent or so efficiency estimated by the Arthur D. Little study for combustion reheating furnaces that are fully equipped with energy-saving features.

Furthermore, energy transfer efficiencies of 90 percent or even better from induction coil to workstock now appear possible with the development of new induction furnace cavities that minimize heat loss from the stock during processing. This improvement could boost the net efficiency of induction steel reheating to more than 30 percent. And induction heating systems can be used with other metals as well, including aluminum, magnesium, and titanium. In Philip Schmidt's estimate, this established and growing electricity-based technology can be expected to expand in industrial use at a healthy rate of 10 to 15 percent per year in coming decades.[13]

Another electrical innovation gets the jump on traditional steel making by starting with steel scrap rather than iron ore.

Another electrical innovation gets the jump on traditional steel making by starting with steel scrap rather than iron ore.[14] Scrap is loaded into an electric arc furnace and graphite electrodes are lowered to a point just above the scrap. When the electricity is turned on, the metal scrap, which forms the path of least resistance between the electrodes, heats rapidly to the melting point. These electric arc furnaces are hot enough to melt a full load of scrap in two hours, whereas combustion furnaces, which are incapable of generating such intense heat, require about eight hours to melt the same amount of scrap.

Electric arc furnaces have been around for some 70 years, but only in the past decade have they come into wide-spread commercial use for the production of common steels. They offer the most efficient way for industry to recycle the nation's inventory of steel scrap, a valuable resource. And this electrical shortcut allows very significant reductions in the total cost of producing a ton of steel.

Starting with scrap eliminates many process steps. Total energy consumed to produce a ton of steel electrically is only 7.4 million Btu, in contrast with 23.5 million Btu to produce a ton by the traditional method. And many pieces of equipment are eliminated as well.

The capital cost of a scrap-based electric steel mill is only $250 per ton per year of steel, in contrast with $1,500 for an integrated steel mill—one that begins, as Abraham Darby did, with iron ore, limestone, and coal. An entire electric steel mill can be built for less than the cost of the blast furnace alone in an integrated mill.[15]

The American Iron and Steel Institute estimates that electric steel making will grow by more than 50 percent by 1988.

These lower capital costs are a major part of the reason that electric steel making is more profitable than the traditional method. In 1979, it cost combustion-based integrated steel operations an average of $447 to produce a ton of steel. Electric steel making operations that began with steel scrap were able to deliver a ton of fresh steel for $306, or about a third less, resulting in a profit per ton about two or three times higher.

Because of their small size, scrap-based steel making operations have come to be known as minimills. This compactness not only means lower capital costs, it means lower costs for space. And that space can be almost anywhere. Neither the need to be near fuel and ore outlets nor the need to satisfy strict air quality requirements for plant emissions limit the siting flexibility of electricity-based steel production systems.

Minimills are now distributed widely over the United States, in contrast to the strong geographical concentration of integrated steel mills in the older, now depressed industrial areas of the Northeast. The American Iron and Steel Institute estimates that electric steel making will grow by more than 50 percent by 1988. The ability to utilize available resources in new ways and the ability to cut the total costs of production by sidestepping previously irreducible costs mark electric steel making as a significant technological innovation.

If the supply of steel scrap were to run out, another electrical innovation that is just beginning to make its place in industry could provide the necessary feedstock.[16]. That process is plasma ore reduction, and what it produces is direct-reduced iron, also called sponge iron. The method uses electricity to generate plasmas—very hot, electrically charged gases—that trigger a rapid chemical reaction in iron ore upon exposure. This reaction separates the iron from the ore's waste products.

This process can be compared to what happens in a traditional combustion-fired blast furnace, where hot gases reduce iron ore to molten iron. But just as electric arc melting is more intense, faster, and hence more efficient overall than combustion melting of scrap, plasma ore reduction promises a quicker and more efficient method to achieve metals extraction. Another plasma-based reduction process, this one directly competitive with combustion-fired blast furnaces, is under development in Sweden. The capital cost of these small plasma reduction units is $150 per ton per year in contrast with $360 per ton per year for cumbersome combustion blast furnaces.

One of the most exciting possibilities currently being explored in the United States is the potential for plasma ore reduction to extract critical alloying agents, now imported, from fairly low-grade domestic ores. For example, the high-grade vanadium ores that combustion processes require to make steel alloys for U.S. industrial and defense purposes come mostly from Africa. If the plasma reduction process can wring the necessary vanadium out of domestic ores instead, it will represent a new use of available resources and a probable cost reduction in the total production bill for a critical metal.

So electrical process technologies offer certain advantages to the steel industry across the board. They typically reduce costs for land, for labor, and for equipment. They are able to draw on raw materials that cannot be used as efficiently, or used at all, in conventional production methods. They generally match or improve combustion-based methods in terms of net energy efficiency, that is, in the percentage of energy from the fuel that winds up in the workstock. They eliminate most of the need for the costly environmental controls, particularly air quality controls, that saddle combustion-based industrial operations. And they provide cleaner, safer, and more comfortable working conditions for mill personnel.

The steel and other metals industries are not the only ones to profit from the use of electricity for high temperature manufacturing applications. In glass manufacturing, according to Charles Berg, "electric melting processes may offer the key to highly valuable advances in productivity."[17] Berg acknowledges that current electric melting methods are not yet applicable to large-scale glass furnaces, but he notes that such methods generally produce higher quality glass, glass with fewer bubbles and greater uniformity, than combustion melting processes do.

Since these defects are largely responsible for scrappage losses in glass container manufacturing, there is a strong possibility that electric melting could boost overall yields. Conventional manufacturing with combustion melting averages yields of about 80 percent, and some large furnaces produce yields as low as 65 percent. Advocates of electric melting believe that, with suitable control, the process could achieve yields of 90 percent or better. So a major benefit of electric heating in the glass industry is the same as in the steel industry—better product quality and a concomitant reduction in expensive stock losses.

Streamlining the Auto Industry

Moving downstream in the manufacturing sequence, we find the automobile industry, a major consumer of both steel and glass. The U.S. auto industry is struggling to bring its production costs under control in order to maintain a competitive place in the world market. One avenue to lower costs and higher productivity appears to be electrification of many of the process technologies used in auto manufacturing.

At General Motors, electricity use has been rising at a steady 3 percent per year over the past decade, while the use of natural gas has been falling. That trend is expected to accelerate as GM tries to streamline its operations, especially those high temperature processes that are major energy consumers: metal casting, melting, heat treating, and forging.[18]

The corporation calculates its energy costs on a relative scale. The relative prices of gas and oil, by this system, are their actual market prices. But the relative price of electricity is counted at one-third its actual cost because its work efficiency is up to three times that of gas in many heating applications. And the relative price of coal is pegged at one and one-half times its actual cost to compensate for the expenses incurred in its use—the expenses of handling, dealing with the ash, cleaning up stack emissions, and so on.

The relative price system is based on the actual work capability of a particular energy source in relation to the actual costs of using it. By this reckoning, electricity is still priced higher per Btu than other fuels, but the gap is considerably narrowed.

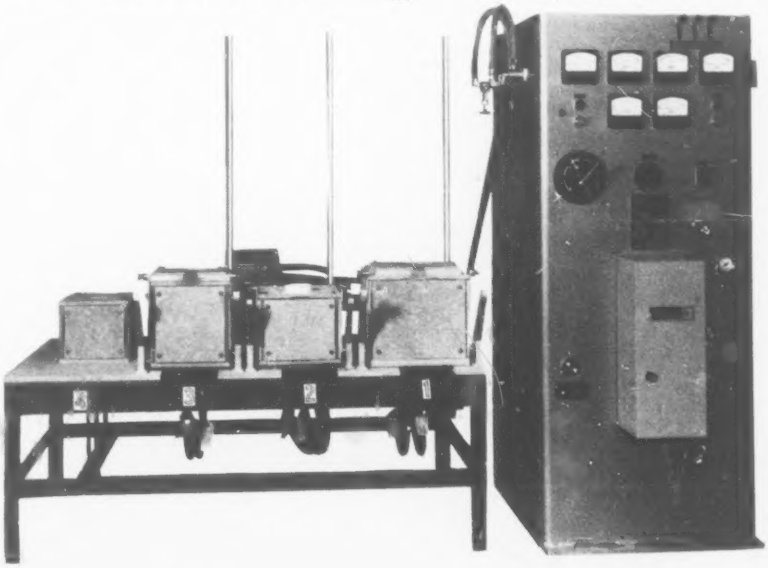
At General Motors, electricity use has been rising at a steady 3 percent per year over the past decade. . . .

Furthermore, the reasons behind the automaker's growing substitution of electricity for gas go beyond the price issue. The relative price differential between electricity and gas was steady during the late 1970s, the time when the substitution trend first began to take hold. But the value of electricity's advantages for certain applications was growing, thereby justifying increased use of the more costly energy source. From GM's point of view, "the principle advantages of electricity in high temperature applications are a potential for lower labor and material costs, reduced factory floor space, and environmental benefits."[19]

Such high temperature applications at General Motors are still fueled about 75 percent by gas and only 25 percent by electricity. The expectation is that this ratio will change dramatically over the next decade, with electricity capturing some 60–70 percent of the high temperature process market.

Besides the high temperature processes that consume the most energy—

This high frequency induction melting system is designed to melt 500 ounces of silver (furnace #1), 250 ounces of platinum (#2), 500 ounces of gold (#3), and small quantities of metals to be assayed (#4).



melting, casting, forging—there are other applications for electricity-based processes in the auto industry. Philip Schmidt's work explores some of these applications.[20]

Electron beams, for example, are used to produce tough and precise welds in auto bodies. The electron gun consists of a heated cathode to produce free electrons, an anode that accelerates them, a focusing coil to narrow the beam, and a deflection coil to manipulate its position. The stream of electrons constitutes an electric current that can be targeted to a spot as small as 0.005 inches in diameter. The heating intensity that goes with this precise focusing is enormous: an electron beam can concentrate ten billion watts of energy per square inch of surface, roughly one million times the intensity of its combustion counterpart, the oxyacetylene torch.

More than half of the roughly 800 electron beam welding units now in industrial use are used for welding auto components.

Electron beam welding has emerged on a commercial scale only during the past decade. It is now used extensively for welding auto components such as the outer body, the frame, the gear assemblies, and hermetically sealed packages. Special advantages over traditional welding methods include the ability to join dissimilar and exotic materials, as well as the ability to produce very deep but narrow welds that minimize surface distortion.

These penetrating welds have made electron beam technology suitable for thick-section joining in the shipbuilding, nuclear, chemical, and petroleum industries. They help provide, for example, aluminum alloy tanks for LNG tankers, pressure vessels and piping for nuclear reactors, and heavy-walled vessels to contain hazardous and highly reactive chemicals. In other words, they are being used increasingly in situations where no separation or leakage can be allowed—where the need is for very durable welds that can be counted on even under the most stressful conditions.

The auto industry remains the leader in the application of electron beam technology. More than half of the roughly 800 electron beam welding units now in industrial use are used for welding auto components. Schmidt reports that the average American new car contains about 180 electron beam welds.

Lasers are another electricity-based technology that automakers have pioneered for industrial use. The world "laser" is an acronym for "light amplification by stimulated emission of radiation." What this means is that a solid or gas—usually carbon dioxide in industry—is stimulated electrically until it emits light particles, or photons. With continual stimulation, a cascade effect occurs, pouring out photons to produce the intense pulse of light known as a laser beam.

The laser beam applies heat with a degree of precision and control unmatched by any other technique, combustion or electrical. Because precise focusing allows very intense energy to be concentrated in one spot, a laser can literally vaporize the material it strikes. Lasers are used in such diverse applications as the drilling of minute air holes in cigarette filters and the drilling of complex patterns of cooling holes through exotic alloys in jet engine turbine blades.

Lasers are also used for such diverse applications as cutting fabric in the garment industry, stripping the plastic insulation from wire, and cutting sheets of titanium to very strict specifications for construction of aerospace equipment. For titanium one-quarter inch thick, Schmidt estimates that a laser cuts about twice as fast as an oxyacetylene torch and twenty times as fast as a mechanical saw, while producing a much cleaner cut than is possible with either of the more traditional methods. And control is so delicate that lasers can inscribe serial numbers or other information on small fragile electronic parts without damaging them. The electronics industry, in fact, accounts for the majority share of industrial laser use.

In the auto industry, the main use of lasers is for surface hardening of metal parts. This heat treatment toughens the parts at just those points of severe stress where they would be most likely to wear out. Crankshafts and gears are prime candidates for laser heat treatment.

Schmidt points out that a special feature of laser technology is the ease with which it can be linked to computer control. In assembly line cutting operations, for example, a computer can vary the intensity of the beam as required for handling many different types of materials, such as fabric, metal, plastic, or wood. And computerized instructions can make the beam trace out a great variety of complex patterns and shapes.

What's more, lasers are easily handled by computerized robots. This compatibility greatly expands the possible roles for lasers in manufacturing. Robots wielding lasers—a marriage of two emerging technologies, both electrical—could accomplish vast amounts of work in a rapid, precise, and economical fashion.

At General Motors, robots are already being developed for applying paint to auto bodies. Human workers now handle this task, requiring large volumes of air to be moved through the spray booths to provide a comfortable and safe working environment. Robots eliminate the need for some of that air, as well as the energy to move it and heat it. Yet the robots themselves require only a few horsepower, drawing minimal electricity.

If electric vehicles are indeed the wave of the future in transportation, then the manufacturing process for automakers will be streamlined even farther. Building an electric vehicle takes less energy than building a conventional one. The drive trains of internal combustion vehicles involve a number of energy-intensive processes that would be eliminated entirely in the manufacture of battery-powered automobiles. But so far, the focus is still on finding more efficient ways to turn out conventional cars.

The electrification trend at General Motors is entirely consistent with the automaker's overall drive to conserve energy. Back in 1972, the company consumed about 206 trillion Btu of energy to produce 6.2 million vehicles. By 1979, it was using only about 200 trillion Btu to produce substantially more cars—nearly 7.3 million. The aim has been to do more with less. Switching many of its manufacturing processes to an electrical base is a logical step in that direction.

Still more industrial uses for innovative electricity-based technologies run the gamut from producing tires to producing TV dinners. Consider, for instance, a new method for setting the brightly colored legends that adorn cans of soda or beer. The traditional approach is to take the entire can in a gas-fired oven for about eight minutes. The innovative method coats the can's surface with a light-sensitive film and then exposes it to ultraviolet rays that can cure the finish in one-fifteenth of a second, according to Charles Berg's estimate.[21]

In Berg's view, this innovation is strikingly similar to James Watt's introduction of a separate condenser in the steam engine (1769). The then-existing Newcomen engine was not very efficient because spraying cool water into the cylinder to condense the steam at every stroke meant a tremendous loss of heat energy. Watt's idea was to isolate the condensing function in a separate chamber that would be kept cool at all times, allowing the steam cylinder to stay hot at all times.

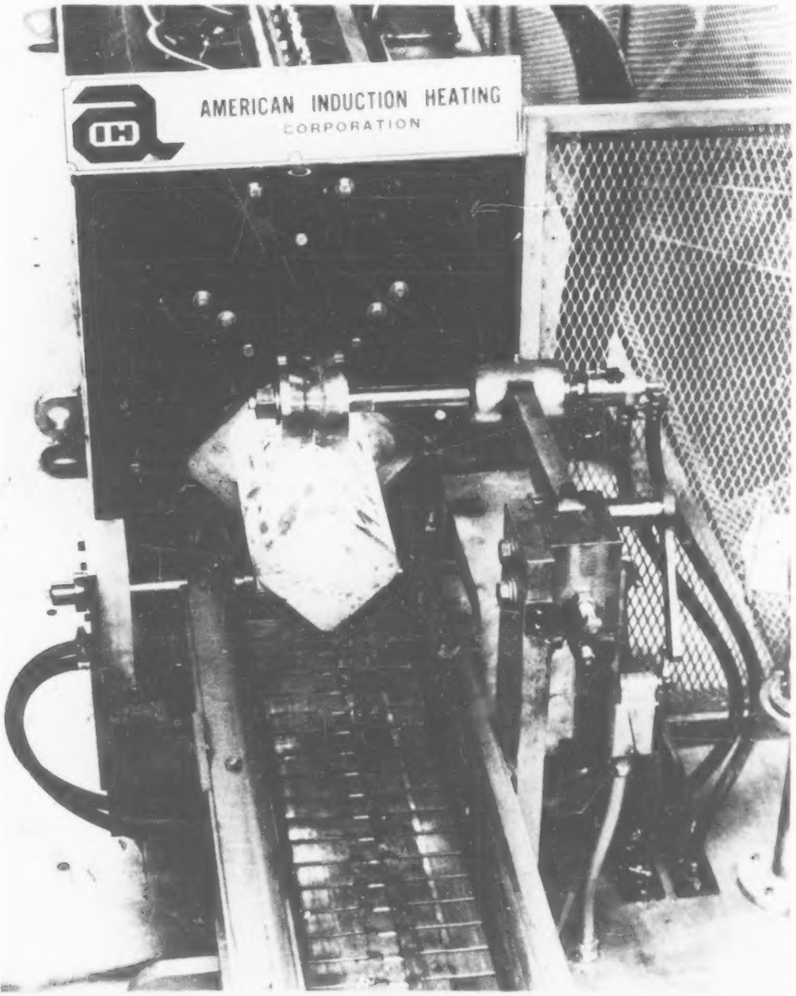
Both Watt's innovation and innovative ultraviolet curing eliminate the need for unnecessary and wasteful heating. In the case of curing, this is possible because only the film to be fused to the can needs to be heated, not the whole can.

This electrical technique carries substantial advantages over combustion firing. Besides providing a cleaner and more comfortable working environment, free of solvent vapors and excess heat, it offers straight dollar savings. According to Philip Schmidt, a large brewery that now uses ultraviolet curing for its beer cans reports that the new electrical system's installed equipment cost is only about 60 percent of the cost of a comparable gas-fired system. What's more, it uses only 40 percent of the energy, requires only 25 percent of the maintenance, and occupies a mere 10 percent of the floor space.[22]

Microwave heating and drying is yet another electrical technology that is finding a wide array of applications. The principle is the same as that of the home microwave oven. When water molecules are exposed to an electric field, they move back and forth with changes in the direction of the current. An oscillating current produces rapid molecular motion, which in turn produces rapid heating or drying of the water-containing substance.

That water-containing substance may be food or lumber or fabric or rubber, to name a few of the products that

Still more industrial uses for innovative electricity-based technologies run the gamut from producing tires to producing TV dinners.



Each hour, this 2000-kw induction coil can heat 11,000 pounds of 5-inch round-cornered billets to a forging temperature of 2250 degrees Fahrenheit.

are now being processed with industrial microwave technology. In the lumber industry, for example, Schmidt reports that, taking both capital and operating expenses into account, microwave drying of hardwoods costs about $40 per thousand board feet compared with $55 for conventional kiln drying. And microwave drying is also much faster: it takes 1 day instead of 25. The paper industry is now drying wood pulp by this method, and textile makers are using microwaves to remove excess moisture from washed fabrics. Rubber and rubber products are heated and cured with microwaves.

Steel parts, plate glass, automobiles, beverage cans, precooked or dried foods, lumber, paper, clothing, and rubber products are only a few items that are beginning to be produced more rapidly and efficiently than ever before by the use of electricity-based technologies. The results are lower production costs and the ability to adapt to changes in the resource base. Electricity can not only replace oil and gas fuels with power made from coal, uranium, or the force of falling water. Electricity can also offer the means to utilize nonfuel resources, such as scrap steel or low-grade domestic ores, in ways that have not been possible using only combustion-based technologies.

Many of our combustion-based processes, despite recent refinements, are more than a century old. Changing conditions require new methods of production.

Historical Perspective

"Not long ago," wrote an observer in 1893, "our period was described as 'the century of steam,' and rightly so; for the steam-engine has been in the front rank of molding modern conditions of industry and commerce. But hardly had the slave Steam grown to its full strength when there appeared for the service of mankind a young giantess. . . . This giantess is Electricity. After remaining behind for decades in the process of growth, . . . she has made such growth that she begins to revolutionize technology.

"Electricity combines . . . a number of brilliant qualities that far outstrip those of steam which fundamentally is able only to push hard. In the first place, electricity's far greater independence of the place where it is generated enables it, however distant from the latter, to carry out its work, while steam can only venture forth a short distance away from its boiler, and even in this restricted case requires the laborious construction of a route. Electricity flies with lightning speed along thin wires over heights, depths and round corners, and is easily distributed, performing its duties in many places simultaneously. But this is the lesser of its advantages. It is above all the universality of its performances which distinguishes electricity. Do we need light? Electricity distributes it to us, and does so better than any other agent. If we require motive power, there is the electric motor, a mere dwarf in comparison with the steam-engine of equal power. We freeze with cold: the same wire which has already afforded us help also yields us heat. . . . And so we can continue and relate all that electricity may be able to do now or in the future, but we prefer to condense it all and say: We possess in electricity every required form of energy, motive-power, light, warmth, etc., in the most convenient and the most concentrated form."[23]

Back in 1893, this paean to electricity was premature for industrial purposes. Most of the innovations described here were barely conceivable in the context of nineteenth century technology. Further, electricity is not likely to entirely replace steam or other combustion-based processes, now or in the foreseeable future. There are still production situations where combustion technologies are the economical and hence the appropriate choice.

But over the long run, an increasing number of industries are finding that the new electrical technologies offer lower costs and higher productivity in manufacturing. Given the nation's recent history of rising industrial costs and sagging productivity, these innovations come none too soon.

Neoindustrialization is the term used today to describe a new type of industrial growth that is beginning to occur in the United States and other advanced nations. Very different from the belching smokestacks and noisy steam engines of eighteenth century industrialization, it promises to boost manufacturing output in ways that are cleaner, quieter, and generally more benign than earlier production methods, both for workers and for the environment.

The movement to revitalize America's productive capacity is already in progress. Those industries that act most decisively to seize the opportunities now available will form its vanguard, and they will be the first to reap its rewards.

. . . an increasing number of industries are finding that new electrical technologies offer lower costs and higher productivity. . . .

Notes

1. This article is based on the work of Charles A. Berg of Charles A. Berg Associates, Buckfield, Maine; on the work of Philip S. Schmidt of the University of Texas and of Energy Management Consultants, Austin, Texas; and on an *EPRI Journal* article reporting Schmidt's work with staff members of the Energy Management and Utilization Division of the Electric Power Research Institute (Mary H. Wayne, "Electrotechnology: Sparking Productivity in Industry," *EPRI Journal*, June 1982, pp. 6–15).
2. Berg's concept of technological innovation is outlined in a letter to Jack Schenk [then Vice President, Economic Policy Analysis], Edison Electric Institute, dated September 9, 1980. The concept is amplified in his paper entitled "A Suggestion Regarding the Nature of Innovation" prepared for the Electric Power Research Institute's Workshop on Energy, Productivity, and Economic Growth, January 12–14, 1981.
3. See the first article in this three-part series (Mary H. Wayne, "Neoindustrialization: The Resource Impetus," *Electric Perspectives*, Fall 1982, pp. 3-8) for a more complete discussion of Berg's findings on the raw materials bind.
4. This material on the form value of electricity is adapted from Wayne, "Electrotechnology," p. 8.
5. Charles A. Berg, "The Role of Electrification in Industrial Processes," an unpublished report prepared for Edison Electric Institute, executive summary, p. ii.
6. See Berg, "The Role of Electrification," p. 9.
7. See Berg, "The Role of Electrification," p. 11.
8. See Berg, "The Role of Electrification," p. 18.
9. See Berg, "The Role of Electrification," p: 18–19.
10. Arthur D. Little, Inc., *Research, Development, and Demonstration*, prepared for U.S. Dept. of Energy, 1978. Figures quoted by Berg, "The Role of Electrification," p. 23.
11. Philip S. Schmidt, "Technical and Economic Comparison, Induction and Gas-Fired Heating of Forging Billets," prepared for the Electric Power Research Institute and reported by Wayne, "Electrotechnology," pp. 12–13.
12. See Berg, "The Role of Electrification," pp. 42–43.
13. See Wayne, "Electrotechnology," pp. 10–11.
14. This discussion of electric steel making is based mainly on the work of Philip Schmidt, as reported by Wayne, "Electrotechnology," pp. 8–10.
15. Science Management Corporation, "Analysis of the Potential for the Introduction of Electrification Technologies into Industry," unpublished report prepared for the Electric Power Research Institute, pp. III–3.
16. This discussion of plasma ore reduction is based on the work of Philip Schmidt, as reported by Wayne, "Electrotechnology," pp. 10, 12–13.
17. See Berg, "The Role of Electrification," p. 72.
18. Gerhard Stein, "General Motors Projects its Future Use of Energy," a paper prepared by General Motors for the Edison Electric Institute Executive Symposium, November 20, 1981.
19. See Stein, "General Motors Projects," p. 6.
20. This discussion of electron beam and laser technology is adapted from a draft report by Philip Schmidt on high temperature materials fabrication, the second in a series of industrial electrification studies sponsored by the Industrial Applications Program in the Energy Management and Utilization Division of the Electric Power Research Institute.
21. Charles Berg, "Dealing with Inflation: The Role of Electricity," an unpublished report prepared for Edison Electric Institute, Summary, p. 10.
22. See Wayne, "Electrotechnology," p. 13.
23. A. Wilke, as quoted by Friedrich Klemm, *A History of Western Technology* (Cambridge: MIT Press, 1964), pp. 355–356.

MHD Inverter a Success

With the successful test operation of a 3.5-megawatt inverter at the Department of Energy's Component Development and Integration Facility, researchers passed a major milestone along the route to harnessing the power of several new generating technologies.

The Facility, located south of Butte, Montana, is testing an advanced process of burning fossil fuels known as magneto-hydrodynamics, or MHD. The inverter changes direct current into alternating current compatible with an electric utility's grid. Without it, it would be impossible to feed the power produced by the MHD process into a utility system.

Development of the $1.5 million inverter was funded by the Electric Power Research Institute in Palo Alto, California. Following successful testing last summer and fall, the inverter was dedicated in October.

The successful operation of this device—the largest MHD inverter developed so far—is particularly significant because similar power conditioning systems are necessary to make electricity produced by the other new technologies, such as fuel cells, batteries, and many small wind turbines, compatible with utility grids and customer equipment. Tests also are being conducted on a 4.5-megawatt (MW) inverter connected to a fuel cell in New York City and a 2.5-MW inverter connected to a battery in Hillsborough Township, New Jersey.

The inverters are needed to produce the smooth, sinusoidal 60-hertz current—alternating current that makes 60 sine-shaped cycles per second—required by utilities. Inverters currently on the market are either too small for utility company use or are relatively unsophisticated. As a result, they can produce current warped by harmonics and cause electromagnetic interference and other electrical distortions. These distortions can cause electrical losses as well as cause utility and customer equipment, ranging from motors and transformers to hair dryers and air conditioners, to overheat. The electrical losses are expensive, and overheating can shorten equipment life.

. . . it is the first time a large-scale MHD inverter has successfully provided power to a utility grid.

The inverter at the MHD facility, which supplies power to Montana Power Company, represents a significant advance not because of any technological breakthrough, but because it is the first time a large-scale MHD inverter has successfully provided power to a utility grid.

"All of the MHD components previously had been operated successfully on an individual basis," said Ralph J. Ferraro, technical manager of Electric Interface and Control Systems at EPRI, "but this is the first time that an MHD generator, an inverter, and a utility grid all have been tied together successfully at this power level. This is a major step toward giving us insights into the way a MHD generator behaves with an inverter connected to it, and into how the power behaves as it flows from the inverter into the grid. This information can provide data leading to the development of a commercial-size MHD plant."

In the MHD process, electric power is generated when extremely hot gases produced by burning fossil fuels at high temperatures are directed through an intense magnetic field at velocities close to the speed of sound. The direct current is generated directly from the flow of gases so hot that they are ionized and exist as a plasma. A direct flow of electrons is tapped from a series of electrodes and fed into an inverter.

The process has the potential capability of generating electric power with up to 50 percent efficiency, compared to the 35 percent efficiency of current coal-fired steam turbine plants. Because MHD is such an efficient process for burning coal and other fossil fuels, MHD plants show promise of emitting far fewer pollutants than conventional combustors.

To achieve this efficiency, the stream of gases generates electricity itself as it moves through the magnetic field and the heat from the gases is used to produce steam to drive a turbine. This dual use of fossil fuel is known as a combined cycle.

The inverter plays two roles in the process. The voltage coming out of the MHD generator can fluctuate between

Contributed by the Editorial Services section of EEI

1,000 and 10,000 volts. The inverter must compensate for these fluctuations as well as see that the alternating current flowing into the grid forms the proper sinusoidal waves.

Construction of the test facility has been a cooperative effort involving the federal government, EPRI, and four private firms. The Department of Energy is funding the Component Development and Integration Facility, which is operated by Mountain States Energy. Westinghouse, Inc. designed and produced the inverter. Avco Everett Research Laboratory provided technical support for the inverter's interface with the MHD generator, which Avco also designed and manufactured. Montana Power provided technical support for the ac interface with its grid.

In August, 1979, EPRI selected Westinghouse to design and construct a power conditioning system to be installed and operated as part of an MHD energy system to be integrated into a utility company grid. The inverter was delivered to the Facility in the fall of 1981.

On April 22, 1982, following eight weeks of pre-operation checkout and startup efforts, the system delivered over 400 kilowatts of alternating current to the Montana Power Company grid. By October, researchers at the Facility, using oil, had produced 4 MW-hours of power from the 1-MW generator. Plans call for testing the MHD process with coal late next year.

At the dedication in October, EPRI President Floyd L. Culler noted that the MHD process is one part of the overall development program in which cooperation has resulted in a balanced, continued exploration of this advanced technology.

"Inverters that can switch dc power to ac are available from manufacturers today, but they have not been designed and built on the large scale necessary for commercial, full-sized use in an MHD power plant," he said. "This inverter represents a significant step in that direction."

The Component Development and Integration Facility is five miles south of Butte in Silver Bow County. The MHD facility covers 53 acres of the 93-acre center.

Plans call for testing the MHD process with coal late next year.

Second Quarter Revenues Advance

Electric utility operating revenues of the investor-owned electric utility industry totaled $23.7 billion in the second quarter of 1982, a 9.3 percent gain over the second quarter of 1981. The increase, achieved despite an 0.8 percent reduction in kilowatt-hour sales to ultimate customers, reflects the effect of rate increases granted since June 1981. Electric operating expenses were up 8.5 percent to $19.7 billion, leading to a 13.5 percent gain in electric utility operating income. Fuel costs, down 5.0 percent from the second quarter of 1981, represented 43.3 percent of operating expenses compared to 49.4 percent for the 1981 quarter. The decrease in the ratio of fuel to operating expenses was caused, in part, by the lower cost of some fuel and by reduced electricity generation. Generation for the entire electric utility industry, including cooperatives and government-owned utilities, was down 3.2 percent in the second quarter.

The increase . . . reflects the effect of rate increases granted since June 1981.

For the 12 months ending June 30, 1982, electric utility revenues were $98.7 billion, 13.3 percent ahead of revenues for the year ending June 30, 1981. Operating expenses increased 12.6 percent. Fuel expenses were 46.0 percent of electric utility operating expenses for the year.

In the second quarter of 1982, other utility operating income increased 47.5 percent to $267 million. This brought total utility operating income to $4.256 billion, an increase of 15.1 percent.

Net income was up 25.1 percent to $3.166 billion. In addition to the recent rate increases, net income was aided by a 13.6 percent gain in other income, a 24.9 percent increase in allowance for funds used during construction (AFUDC), and $25 million of extraordinary income. More than half of the net income increase between the second quarter of 1981 and the second quarter of 1982 was caused by the AFUDC increase, which is noncash accounting earnings.

Preferred dividend requirements increased 9.9 percent, leaving $2.543 billion available for common stock dividend requirements, a 29.5 percent increase over the second quarter of 1981. Of the $2.543 billion of net income available for common, $1.702 billion is AFUDC. The $2.543 billion of net income available for common translated to earnings per share of 60 cents, a 15.4 percent quarterly increase. The average number of shares increased 11.9 percent over the same quarter of 1981. Earnings per share for the year ending June 30, 1982 were $2.92, a 14.5 percent increase over the $2.55 reported for the comparable period ending in 1981.

AFUDC represented 53.8 percent of the net income before preferred dividends, virtually unchanged from the second quarter of 1981. This measure of the cash content of earnings illustrates the continuing electric utility financial problem. AFUDC earnings do not contribute to cash flow in the year the earnings are recognized. On an annual basis, AFUDC as a percent of net income increased to 44.4 percent for the year ending June 30, 1982 compared to 44.1 percent for the year earlier.

Interest coverage improved during the quarter and year. Coverage before income taxes and with AFUDC was 2.38 for the second quarter of 1982 compared to 2.21 for the second quarter of 1981. For the years ending June 30, 1982 and 1981, the ratios were 2.65 and 2.53, respectively.

The consolidated income statement shown on Table 1 is based on unaudited reports received from electric utilities. These reports accounted for 94 percent of the industry's revenues. Data were expanded to represent the entire investor-owned electric utility industry.

Equity Shareholder Associations

Electric utility equity shareholders are becoming increasingly vocal. Either as a result of dissatisfaction with how well their interests are being presented to various audiences or out of a sense that utility managers need help, they have organized at least 11 associations in several parts of the country during the past 6 years to promote their interests to regulators, consumer and environmental groups, and other special interest concerns.

Contributed by the Finance Department of EEI

Table 1
INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY STATEMENT OF INCOME
(Unaudited, Millions of Dollars)

	Three Months Ended			Twelve Months Ended		
	6/30/82	(R) 6/30/81	% Change	**6/30/82	(R) 6/30/81	% Change
Total Electric Operating Revenues	$23,710	$21,699	9.3	$98,731	$87,126	13.3
Electric Operating Expenses						
Fuel	8,541	8,991	− 5.0	37,410	35,113	6.5
Other Operation & Maintenance Expenses	6,236	4,986	25.1	23,171	19,506	18.8
Depreciation & Amortization	1,844	1,665	10.8	7,165	6,403	11.9
Taxes Other Than Income Taxes	1,737	1,605	8.2	6,922	6,269	10.4
Income Taxes (Federal & Other)	445	174	155.7	2,986	1,890	58.0
Provisions For Deferred Income Taxes-Net	373	593	−37.1	1,765	2,130	− 17.1
Investment Tax Credit Adjustments-Net	545	169	222.5	1,898	934	103.2
Total Electric Operating Expenses	19,721	18,183	8.5	81,317	72,245	12.6
Electric Utility Operating Income	3,989	3,516	13.5	17,414	14,881	17.0
Other Utility Operating Income	267	181	47.5	1,079	893	20.8
Total Utility Operating Income	4,256	3,697	15.1	18,493	15,774	17.2
Other Income & Deductions-Net	435	383	13.6	1,799	1,407	27.9
Allowance For Other Funds Used During Construction	963	743	29.6	3,475	2,779	25.0
Total Income	5,654	4,823	17.2	23,767	19,960	19.1
Interest On Long-Term Debt	2,860	2,500	14.4	10,905	9,300	17.3
Other Interest Expenses & Charges	392	387	1.3	1,630	1,456	12.0
Allowance For Borrowed Funds Used in Construction (Cr.)	(739)	(620)	19.2	(2,821)	(2,280)	23.7
Total Interest & Charges	2,513	2,267	10.9	9,714	8,476	14.6
Net Income Before Extraordinary Items	3,141	2,556	22.9	14,053	11,484	22.4
Extraordinary Items	25	(26)	—	125	(5)	—
Net Income	3,166	2,530	25.1	14,178	11,479	23.5
Preferred Stock Dividends Declared	623	567	9.9	2,381	2,219	7.3
Net Income Available For Common	$ 2,543	1,963	29.5	11,797	9,260	27.4
Earnings Per Share*	$ 0.60	$ 0.52	15.4	$ 2.92	$ 2.55	14.5

*Based on average shares for each quarter.

**Certain accounts in the combined four quarters have been revised from that previously presented.

NOTE: The income statement is a "net" or "consolidated" statement. The duplicative effect of including resale revenues by one investor-owned electric utility to another has been eliminated.

The shareholder associations' chief audience is state regulators.

Electric Utility Shareholder Associations

- American Society of Utility Investors
- Arizona Public Service Shareholders Association
- Association of Detroit Edison Shareholders*
- Association of Investors in New York Utilities
- Association of South Carolina Electric & Gas Company Investors
- California Association of Utility Shareholders
- Louisiana Utility Shareholders, Inc.*
- National Association of Shareholders*
- Utah Shareholders Association of Utah
- Wisconsin Utility investors, Inc.

*The degree of activity or the size of membership of these associations has not been determined.

Today there are at least 10 electric utility shareholder associations in existence. Their organizational structures, financial support, and tactical approaches vary, but they all have the common objective of protecting and improving the financial health of the utilities their members have invested in. More specifically, most associations seek 3 goals:

- to improve the regulatory climate through interaction with legislative and administrative bodies;
- to educate and inform utility shareholders about issues that may affect their investments; and
- to promote good relations between association members and utilities.

The approaches taken by investor groups to achieve these goals run from direct intervention in rate hearings and legal proceedings to subtle appeals to the general public. Some groups such as the California Association of Utility Shareholders, confront directly the regulatory, consumer, and other special interest groups that have traditionally intervened in rate hearings to oppose utility policies or activities. Others, such as the Association of South Carolina Electric and Gas Company Investors, appeal directly to the public by asking individual members to intervene on their own behalf. By doing so, the South Carolina Association hopes to change the electric utility stockholder's public image from that of a Madison Avenue tycoon to that of a Main Street, U.S.A. citizen. Although the impact of these particular approaches is difficult to quantify, supporters feel they have been fairly successful in achieving desired results.

The shareholder associations' chief audience is state regulators. Consequently, most of them have organized on a state-wide basis. One exception, the American Society of Utility Investors, is attempting to build national representation of electric utility shareholders. However, at present, its primary emphasis is on the Pennsylvania regulators' treatment of General Public Utilities following the Three Mile Island accident. Most associations involve themselves only in activities that affect electric utilities in the state, but a few have expanded their efforts to include gas, water, and telephone companies. In all cases, investors in the local electric utilities receive the majority of the association's representation.

Most shareholder associations are managed by an Executive Board or Board of Directors, the members of which are volunteers. The day-to-day administrative duties are managed by an Executive Director or President, usually the chief spokesman for the association. A few of the financially stronger associations, such as the California Association of Utility Shareholders, have full-time directors. However, the clear majority are organized and managed by volunteers.

Most shareholder associations are financed by membership dues. The dues usually range from $10 to $20 per member, and membership in dues-collecting associations ranges from 1,500 in the Association of South Carolina Company Investors to 8,000 in the California Association of Utility Shareholders. The few associations financed through voluntary contributions tend to have larger memberships because marginally interested investors are more willing to join. The Wisconsin Utility Investors, Inc., for example, is financed entirely through voluntary contributions and claims 22,000 members.

In an effort to maintain credibility among regulators, the media, and prospective members, most associations carefully avoid any direct support, financial or otherwise, from utilities. Most utilities, however, do allow associations to solicit new members via "piggyback" mailings, in which membership brochures produced and paid for by the associations are included with quarterly stockholder reports or dividend checks mailed by the utilities. Because the brochures are small, they do not affect utilities' postage costs.

Members are obtained primarily through either piggyback solicitation or direct solicitation by the shareholder associations. To date, between 50,000 and 60,000 shareholders belong to one of the seven major associations for which membership data are available. Utility representatives and association members believe that the demographic composition of the shareholder associations is very similar to that of the electric utility shareholders in general.

The potential benefits to utility companies from equity shareholder associations are considerable. In most cases, shareholders support utility positions and activities that may enhance the value of their investment. They educate and inform members about current issues in the electric utility industry through regular newsletters, educational brochures, and appearances at public meetings by association-appointed speakers. For example, "How Much is Enough" and "The Myth of the Guaranteed Profit," both published by Wisconsin Utility Investors, Inc., educate investors on issues such as "excessive" and "guaranteed" profits of utilities and other regulated monopolies.

Associations also provide the means for presenting shareholder support with a single and potentially influential voice. They have been able to track and address local utility-related issues with apparent effectiveness through rate hearing intervention and media relations activities. One of the earliest examples of their effectiveness was the result of action taken by a predecessor group of the Utah Shareholders Association of Utah. The group intervened in three Utah Power and Light (UPL) rate cases in 1976 and argued that unless rates were increased by the amount sought by the utility, corporate earnings would fall, causing equity to sell below the book, which would, in turn, result in a fundamental confiscation of shareholder property without reasonable compensation. The commission allowed 96 percent of the increase sought by UPL, and UPL credited much of the success to the shareholder's intervention.

Since that time, shareholder associations have confronted regulators and special interest concerns regarding issues when few voices favorable to utilities were being raised. Of course, differences do exist between shareholder associations and utilities (for example, the issuance of additional shares of common stock below book value) which may, at times, result in the associations working against the immediate objectives of utility management. Still, utility representatives are generally supportive and occasionally enthusiastic about the investor groups because they provide a "useful format" for investor activity and a balance to other more vocal advocates.

The potential benefits to utility companies from equity shareholder associations are considerable.

The Cost of Household Electricity

As shown on Table 1, the average price of electricity consumed in residential service almost tripled from 1969 to 1981, rising from 2.09 to 5.89 cents per kilowatt-hour (kwhr). Economies of scale and advances in boiler technologies pulled the price down steadily until 1969 when it reached an all-time low. Since then several factors—the growing number of environmental control requirements, unusually high rates of inflation, and more frequent construction delays—have pushed the price back beyond its 1931 level of 5.78 cents per kwhr.

By 1981 the residential electricity price index, which covers certain fixed quantities of electricity consumed, increased 191.5 percent above the 1967 base of 100, while the Consumer Price Index (CPI) rose only 172.3 percent. With only 3 exceptions (1970, 1973, and 1979), the electricity price index has risen faster than the CPI for the last 12 years. However, the electricity index did not jump ahead of the CPI until after the 1973–74 oil embargo.

Table 2 shows that Americans spent 2.2 percent of their disposable personal income, or income after taxes, for household electricity in 1981, up from 1.4 percent in 1969. This outlay compares with 16.2 percent for food, 14.6 percent for housing, and 6.6 percent for clothing and shoes. The amount spent for electric service was less than half that spent on gasoline and motor oil. Total personal expenditures on energy used directly by households (electricity, gas, fuel oil, coal, gasoline, and motor oil) amounted to 9 percent of disposable personal income in 1981.

. . . Americans spent 2.2 percent of their disposable personal income, or income after taxes, for household electricity in 1981. . . .

Table 1. Residential Electricity and the Cost of Living*

Year	Average Revenue per Residential Kilowatt-hour Sold (cents/kwhr)	Price Index Numbers** Residential Electricity (year's average)	Price Index Numbers** Consumer (year's average)
1981	5.89	291.5	272.3
1980	5.12r	253.4	247.0r
1979	4.43r	219.1r	217.7
1978	4.03	203.4r	195.3
1977	3.78	189.3	181.5
1976	3.45	177.6	170.5
1975	3.21	167.0	161.2
1974	2.83	147.5	147.7
1973	2.38	124.9	133.1
1972	2.29	118.9	125.3
1971	2.19	113.2	121.3
1970	2.10	106.2	116.3
1969	2.09	102.8	109.8

*Data include Alaska and Hawaii.

**The Index numbers are percentages of the year 1967, used by the U.S. Bureau of Labor Statistics as the base period. Electricity index numbers cover fixed quantities of electricity used.

r = Revised from previous data.

Sources: Monthly Labor Review; EEI Statistical Year Book.

Contributed by the Statistical Department of EEI

Table 2. Direct Personal Expenditures on Energy as Percentages of Disposable Personal Income 1969-1981 (Millions of $)

		Personal Consumption Expenditures Components of GNP				
		Household				
Year	Disposable Personal Income	Electricity	Gas	Fuel Oil and Coal	Automotive Gasoline and Oil	Total Direct Energy
1981	2,029,148	45,232	21,538	19,748	96,783	183,301
%	100.00	2.23	1.06	0.97	4.77	9.03
1980	1,824,076	37,104	19,470	18,998	86,953	162,525
%	100.00	2.03	1.07	1.04	4.77	8.91
1979	1,650,155	31,329	16,509	16,105	66,576	130,519
%	100.00	1.90	1.00	0.98	4.03	7.91
1978	1,473,991	28,503	14,380	11,915	51,242	106,040
%	100.00	1.93	0.98	0.81	3.48	7.20
1977	1,314,019	25,650	12,800	10,668	48,126	97,244
%	100.00	1.95	0.98	0.81	3.66	7.40
1976	1,194,359	21,940	10,973	9,824	43,973	86,710
%	100.00	1.84	0.92	0.82	3.68	7.26
1975	1,086,658	19,999	9,263	10,236	39,509	79,007
%	100.00	1.84	0.85	0.94	3.64	7.27
1974	984,627	16,503	7,589	9,562	36,431	70,085
%	100.00	1.68	0.77	0.97	3.70	7.12
1973	901,663	13,852	6,725	7,722	27,813	56,112
%	100.00	1.54	0.74	0.86	3.08	6.22
1972	801,299	12,314	6,541	6,270	24,879	50,004
%	100.00	1.54	0.82	0.78	3.10	6.24
1971	746,433	10,936	5,699	6,867*	23,498	47,000
%	100.00	1.47	0.76	0.92	3.15	6.30
1970	691,699	9,824	5,262	6,752*	22,211	44,049
%	100.00	1.42	0.76	0.98	3.21	6.37
1969	634,386	8,905	4,938	6,358*	20,894	41,095
%	100.00	1.41	0.78	1.00	3.29	6.48

*Designated "Other Fuel & Ice" rather than "Household Oil & Coal."

Source: July issues of Survey of Current Business, U.S. Department of Commerce.

Supreme Court Rules PURPA Constitutional

In a 5-4 decision, the U.S. Supreme Court has held that Titles I and III and Section 210 of the Public Utility Regulatory Policies Act (PURPA) are constitutional, reversing a decision by the U.S. District Court for the Southern District of Mississippi. The majority opinion, written by Justice Blackmun, concludes that:

> The challenged provisions are within Congress's power under the Commerce Clause, and
>
> The challenged provisions do not infringe on state sovereignty in violation of the Tenth Amendment.

Four justices (Burger, O'Connor, Powell, and Rehnquist) dissented in part.

History of the Case: The case began in 1979 when the State of Mississippi and the Mississippi Public Service Commission began an action in a U.S. District Court in Mississippi seeking a declaratory judgment that much of PURPA was unconstitutional. Mississippi challenged Titles I and III of the statute, as well as Section 210. These provisions of PURPA require each state commission to consider a list of "standards" for electric (Title I) and gas (Title III) utilities. The commissions are not required to adopt the standards. Section 210 of PURPA requires state commissions to implement rules, which PURPA directs the Federal Energy Regulatory Commission (FERC) to promulgate, encouraging cogeneration and small power production.

The district court held that the provisions Mississippi had challenged were unconstitutional. It reasoned that the Commerce Clause of the U.S. Constitution does not authorize Congress to take over "the regulation and control of public utilities;" PURPA "does not even attempt to regulate commerce among the several states;" and PURPA infringed on state sovereignty in violation of the Tenth Amendment, as it constituted "a direct intrusion on integral and traditional functions of the State of Mississippi."

FERC and the Secretary of Energy appealed directly to the Supreme Court, which reversed the decision in June.

. . . the Court stated that it was "difficult to conceive of a more basic element of interstate commerce than electric energy". . . .

Contributed by the Rate Regulation department of EEI

Commerce Clause: The Court "readily" concluded that the district court's analysis was "without merit so far as [it concerned] the Commerce Clause." Noting that the Mississippi utilities purchased and sold power in interstate commerce, the Court stated that it was "difficult to conceive of a more basic element of interstate commerce than electric energy" and that no state relied "solely on its own resources" in its production. The Court further observed that it "heretofore [had] indicated that federal regulation of intrastate power transmission may be proper because of the interstate nature of the generation and supply of electric power."[1] Therefore, PURPA could be invalidated on Commerce Clause grounds only if Congress's findings—that the regulated intrastate activities of utilities affected interstate commerce and that there is a reasonable connection between the regulatory means selected and the asserted ends—lacked a rational basis. The Court concluded that PURPA and its legislative history revealed rational bases for concluding that electric energy affects interstate commerce and that "Congress was not irrational" in concluding that the "limited federal regulation" in PURPA "was essential to protect interstate commerce."

Tenth Amendment—Enforcement by States: The constitutionality of federal use of state regulatory machinery for federal regulatory purposes was "an issue of first impression" to an extent. Although §210 appeared on its face "to be the most intrusive of PURPA's provisions," its constitutionality was "the easiest to resolve." FERC's authority to exempt Qualifying Facilities from state laws and regulations merely

> pre-empt[s] conflicting state enactments in the traditional way. Clearly, Congress can pre-empt the States completely in the regulation of retail sales . . . and in the regulation of transactions between . . . utilities and congenerators.

Congress may also require the states to implement the FERC rules and to adjudicate disputes arising under them. Earlier cases have upheld Congress's authority to require state courts of "adequate and appropriate" jurisdiction to hear federal claims if they heard analogous state causes of action.[2] Since the Mississippi Public Service Commission (PSC) had jurisdiction to entertain claims analogous to those arising under PURPA, it can "satisfy §210's requirements simply by opening its doors to claimants." The Court dismissed the fact that the PSC had "administrative as well as judicial duties" as "of no significance." Any other conclusion

> would allow the States to disregard both the pre-eminent position held by federal law throughout the Nation . . . and the congressional determination that the federal rights granted by PURPA can appropriately be enforced through state adjudicatory machinery.

Tenth Amendment—Mandatory Consideration of PURPA Standards: The Court's discussion of the constitutionality of PURPA's requirements that state commissions consider certain ratemaking standards involved issues of federalism vigorously contested by the dissent. The Court reasoned that Congress "could have pre-empted the field" of private utility regulation from the states and that

> PURPA should not be invalid simply because, out of deference to state authority, Congress adopted a less intrusive scheme and allowed the States to continue regulating in the area on the condition that they *consider* the suggested federal standards.

The condition of remaining in the field—that state commissions consider the PURPA standards—is not "a constitutionally improper one." PURPA does not "directly compel" the states to enact a legislative program, and it does offer the states a vehicle for remaining active in the rate area.

Tenth Amendment—Procedural Requirements: The Court upheld the notice and comment procedures required by Titles I and III for the same reasons as the consideration provisions. Since Congress can constitutionally require states to consider the standards, it can also require "certain procedural minima" be followed in that consideration.

Dissenting Opinions: Justice Powell dissented only from the holding that Congress could impose procedures for the states to follow in considering the PURPA standards. Such a requirement, he maintained, "breaks with . . . longstanding deference to principles of federalism" by "forc[ing] federal procedures on state regulatory institutions." Justice O'Connor, with whom Chief Justice Burger and Justice Rehnquist joined, dissented from the holdings that Congress could require consideration of PURPA standards and that it could prescribe procedures. She argued that those requirements regulated states as states, infringed on attributes of state sovereignty, and impaired states' ability to structure their operations in areas of traditional governmental functions, all in violation of the Tenth Amendment.

The Court's discussion . . . involved issues of federalism vigorously contested by the dissent.

All nine justices agreed that the challenged provisions were within Congress's power under the Commerce Clause and that Congress could require implementation of §210 regulations by the states.

Notes

1. In *FPC v. Florida Power and Light Co.*, 404 U.S. 453 (1972).
2. *Testa v. Katt*, 330 U.S. 386 (1947); *Mondou v. New York, N.H. & H.R. Co.*, 223 U.S. 1 (1912).

Book Review

Global Insecurity: A Strategy for Energy and Economic Renewal

Edited by Daniel Yergin and Martin Hillenbrand
Houghton Mifflin, 1982
Boston 427 pp.

By Charles Linderman

As editors Yergin and Hillenbrand explain in its preface, *Global Insecurity* "is not a book about energy itself, but about the economic, social, and political consequences of the energy problem." Agreeing on "the need to maintain economic growth" and "the reasonable probability of recurrent energy problems," the authors explore the interaction of the two issues to anticipate "how these consequences might be felt in the rest of the 1980s and 1990s." Thirteen authors from various parts of the world contributed essays to the work, which is the result of a four-year research project sponsored by the Atlantic Institute for International Affairs and cosponsored by the Harvard University Energy Security Program.

However, the authors do not offer this grave picture of "what could be" as a forecast of "what will be."

Like other studies that have emerged recently from the energy community, *Global Insecurity* claims that although we currently enjoy what has been labeled an oil glut, it is at best temporary. The authors describe the oil glut of 1981 and 1982 as a sedative which lulls people into ignoring the challenge of permanently adjusting the economy to higher-priced fuels. "The realities of world energy are not necessarily very appealing, and when things appear to be going right, there is a natural enough predilection to want to forget about them, to persuade oneself that the problem is solved."

The authors of *Global Insecurity*, however, are not persuaded. Indeed, they conclude that the era of cheap energy is coming to a sputtering but nonetheless permanent end, and they attribute to its demise the end of full employment in both the United States and Western Europe. Focusing on major oil consumers—the United States, Western Europe, Japan, and oil-importing developing countries—the essays examine the effects of energy issues on the social and political stability of democratic nations, including their potential for causing international conflicts. They point to increasing energy costs as a source of continuing problems, citing huge national debts and instinctive self-protectionism as factors that could influence international affairs adversely.

As one might expect, the book criticizes the Reagan administration, accusing it of delivering "a confusing message of complacency to the public" about the nation's energy situation: "For instance, the Reagan administration has put great emphasis on developing a military deterrent capability for the Arabian/Persian Gulf, in effect recognizing the extent of the problem. Yet its domestic energy policies appear based on the assumption that all problems are over."

The authors maintain that if we do not adjust to the realities of world energy supply and demand "by increasing energy supplies outside OPEC . . . , much of the balancing could come from lower real incomes and reduced economic growth." Moreover, they warn, if industrialized nations of the West solve their energy problems merely "by transferring the whole cost to weaker nations . . . in the form of depressed economic standards," they will threaten "the strength and stability of the international system as a whole."

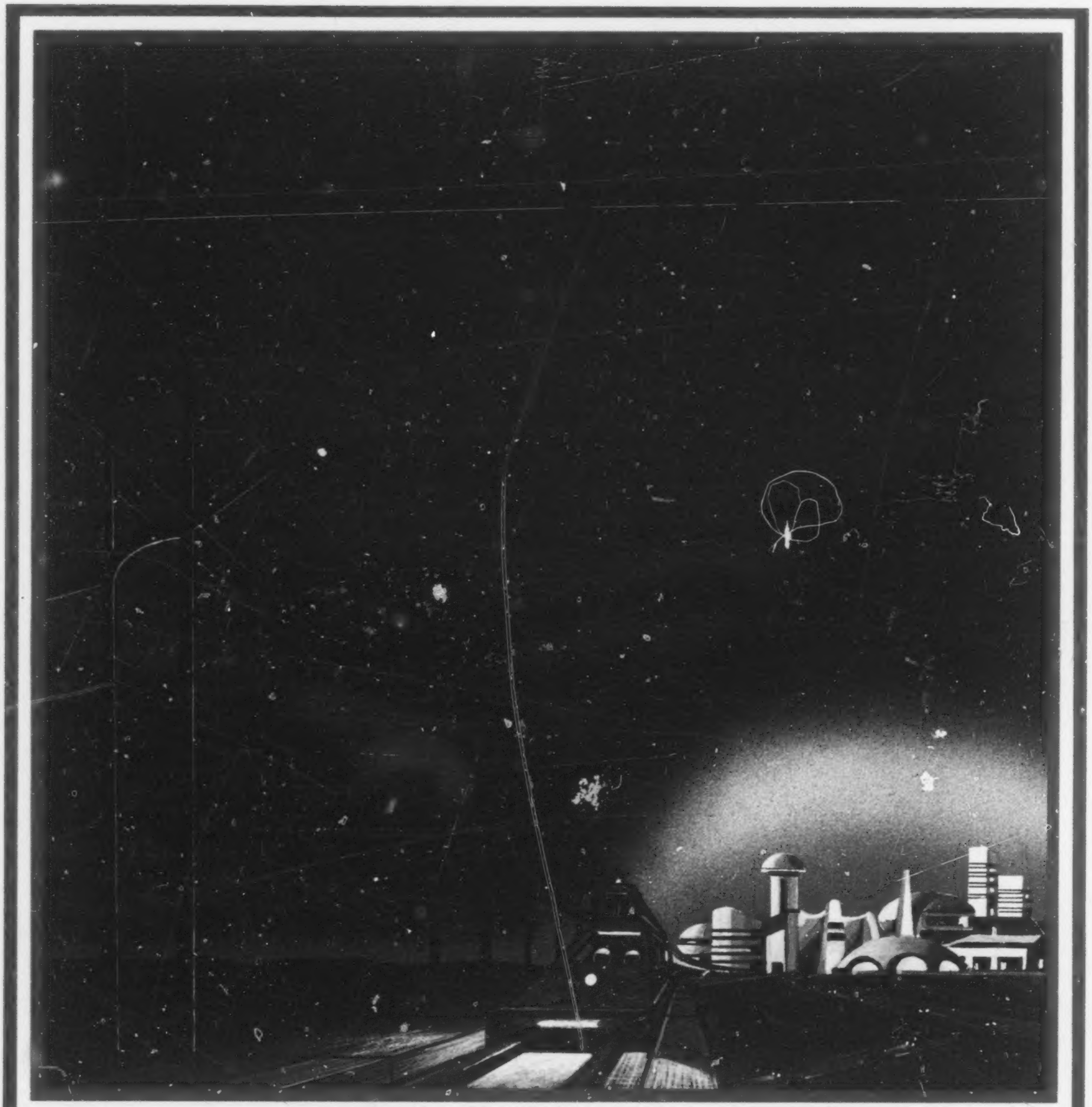
However, the authors do not offer this grave picture of what "could be" as a forecast of what "will be." They also argue "that a reasonable adjustment, while not foreordained by any means, is certainly possible," and they produced this book in hopes that it will "stimulate an international debate that will help to avoid or at least minimize the risks" of future energy crises and global insecurity.

A stimulating book, *Global Insecurity* deserves careful reading by all electric utility industry employees, especially those whose companies remain substantially reliant on oil for generating electricity.

Charles Linderman is Manager of Fossil Fuel Programs at Edison Electric Institute.

Electric Perspectives

Spring 1983



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Will Rogers, May 26, 1935

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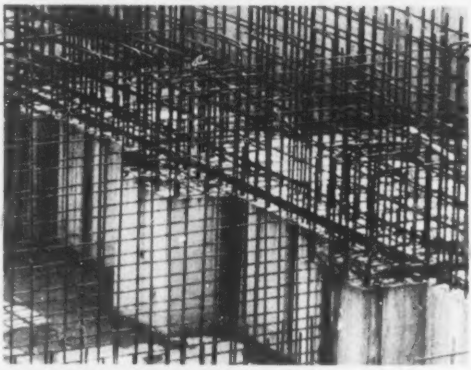

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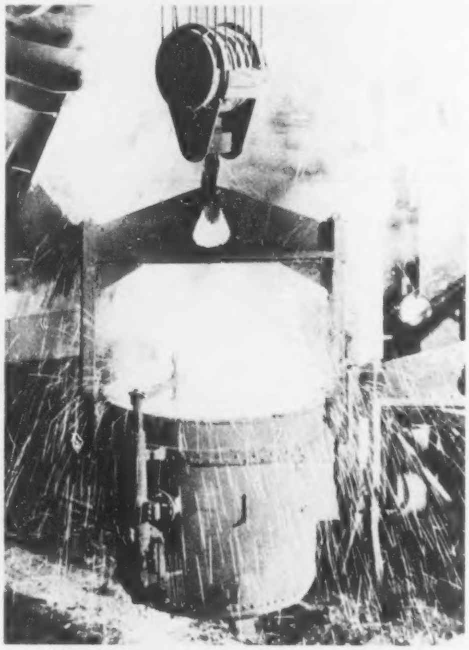

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COVER
This issue of Electric Perspectives *looks forward—from forecasting load growth and short-term fuel prices to forecasting the evolution of U.S. society—and listens to a former utility executive explain how the industry met some previous challenges.*

Illustration by Michael J. McGurk

Electric Load Growth: Are Utilities Underforecasting?

By John R. Siegel and
John O. Sillin

"An economist is a man who can tell you what can happen under any given conditions, and his guess is liable to be just as good as anybody else's."

Will Rogers, May 26, 1935

Are electric utilities underforecasting? We believe the answer is yes, and that capacity expansion decisions based on underforecasts of load growth could have serious implications for the future cost and reliability of electricity. If so, the U.S. could be headed for a repetition of the late 1960s: reserve margins dropped below 20 percent for a sustained period and the utility industry's only recourse was to order significant quantities of short lead-time, high operating cost generating equipment.

Why are utilities underforecasting? One explanation is that utility system planners—currently using highly sophisticated econometric models capable of predicting not only the arrival date of the Smith's next baby, but also his future occupation and productivity—are ignoring potential long-term macroeconomic trends.

Very simply, planners appear to be predicting the next 20 years of load growth on the basis of trends established in the 1970s . . . a tumultuous decade, "an aberration" in the words of Paul Volcker, a period in which domestic energy prices quadrupled, inflation twice exceeded 12 percent, and economic growth fell to 60 percent of that which occurred in the 1950s and 1960s.

It would also appear that utility planners give little credibility to current predictions of economic recovery, much as Will Rogers was suggesting in the Great Depression. Further, they tend to discount current trends in the domestic and international energy picture that suggest energy will not be the factor in retarding economic growth in the 1980s that it was in the 1970s.

Another explanation is that the utility executive is in no mood to listen to projections of "growth" that suggest he should commit his company to a multi-billion dollar investment, which when completed, will approximate half his company's assets. And why not? The consistently poor performance of end-use forecasting models in the early 1970s and the resultant "over-capacity" of generation capability have made the chief executive wary of projections of enhanced load growth . . . and his job extremely demanding. The over-capacity situation—in combination with a decade of high inflation, poor financial markets, and adversarial rate regulatory commissions—has demanded pre-eminence in utility executives in the areas of financial management and public relations. Maintaining the company's historical dividend position—and in some cases, its solvency—has become the main objective of most chief executives.

Fortunately, times are changing. Inflation and interest rates are down, rate regulatory commissions are becoming more responsive, and the economy appears on the verge of a sustained recovery . . . and with it, electric load growth. However, utility and non-utility projections of national load growth currently approximate annual rates of 3 percent. These projections are consistent with a continuation of the economic trends prevalent since the oil embargo of 1973. But, are utilities prudent in assuming a continuation of the economic conditions which resulted in a 3 percent average rate of load growth? If the economy does begin to recover strongly before mid-decade, it is possible that the United States could experience an electric load supply-demand mismatch at the end of this decade. Such a mismatch, and accompanying run-up in electricity prices (thank you Adam Smith), could act as a brake on the nation's economic growth, and in turn, electric growth . . . i.e., low projections of load growth could become a self-fulfilling prophesy.

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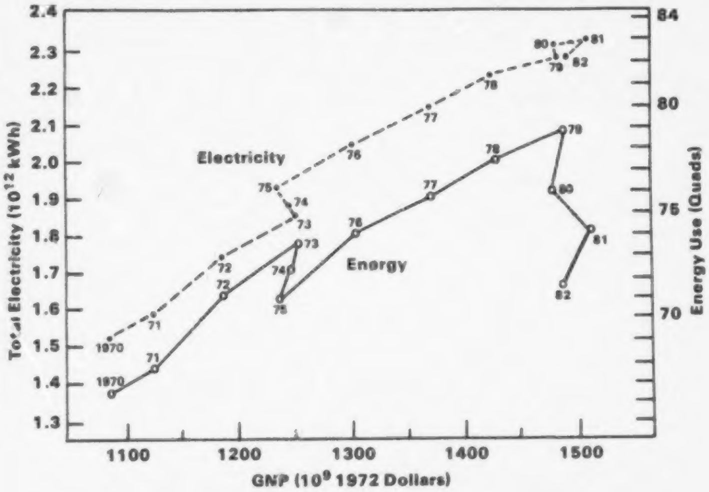
John O. Sillin is a Senior Associate in the Energy and Environment Division of Booz, Allen & Hamilton, Inc. His work has focused on electric and gas utility planning, policy, and operation issues. He holds a Masters Degree in Business Administration from the New York University Graduate School of Business.

The views presented are those of the authors.

EXHIBIT 1
ELECTRICITY USE INCREASED CONSISTENTLY THROUGHOUT THE 1970s; THE ECONOMY AND TOTAL ENERGY USE SUFFERED MAJOR PERTURBATIONS



Sources: GNP: Economic Report of the President; Electricity Use: 1970-1972; Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry*, 1973-1980; Energy Information Administration, *Monthly Energy Review*, April 1981.

It is our contention that inconsistent economic policies and rapid increases in oil prices resulted in the high inflation and sharply lower economic growth of the 1970s. President Reagan's economic program has as its objectives the re-establishment of stable economic policies and the implementation of increased incentives to save and invest. These policies should, in turn, set the stage for economic recovery. While these policies have not yet been fully implemented, and the results today are mixed, both the administration and the Democratic forces in Congress are predicting an improvement over conditions realized during the 1970s. Beginning in 1983, and continuing through the rest of the 1980s, various forecasts call for real economic growth to average between 3 and 4 percent per year. Events on the international energy scene, primarily the softening of the world oil market, will also help to stabilize economic conditions.

If economic conditions gradually improve, it is our contention that electric load growth will also increase—above the 3 percent average of the 1973–1981 period. Further—and to those that argue that energy intensive industry has left the U.S.—electricity is more favorably price positioned relative to oil and natural gas than at any point in the last 20 years. This will enable electricity to penetrate industrial process and home heating markets which have been dominated by oil and natural gas since the 1950s.

Thus, electric utilities that assume a continuation of recent economic trends could be significantly underforecasting load growth. Capacity expansion decisions based on these forecasts have serious implications for electricity's future cost and reliability, and, in turn, for the outlook for a sustained increase in economic growth.

But independent of which economic scenario utility executives care to believe—and we present three: a continuation of the economic trends of the 1970s (the "OPEC" or "low-growth" scenario), partial recovery (the "Congressional" scenario), or full recovery (the "supply-side" scenario)—*the need to order new plants exists today.* Assuming a ten-year lead time for licensing and construction, *no plant retirements,* and the maintenance of a 20 percent reserve margin, for a:

- 3 percent load growth (the OPEC scenario), an average new plant ordering rate of 25 GWe (gigawatt) per year should commence in 1984;
- 4 percent load growth (partial recovery), an average new plant ordering rate of 40 GWe per year should begin in 1983;
- 5 percent load growth (full recovery), an average new plant ordering rate of 70 GWe per year should begin in 1983.

Roughly, these rates compare to the 1965–1974 average ordering rate of 40 GWe per year and the *effectively zero ordering rate of 1975–1982.* Thus, even for a low-growth scenario, utilities must begin considering the addition of new generation capacity.

It is likely, however, that the utility industry will continue to mark time until economic conditions fully stabilize and future electric requirements become explicity defined. Unfortunately, this stabilization process could take until 1985. At that time, following two solid years of economic recovery and electric growth in the 4–5 percent range, chief executives will begin to appreciate more fully the potential for and implications of inadequate reserve margins in the early 1990s. If this scenario holds, an unprecedented demand could be put on the power industry to supply new generation equipment.

Historical Perspectives: Economic, Energy, and Electric Load Growth

To argue our case—that electric utilities are under forecasting—we will first review the economic environment of the 1970s, including the energy shocks and high inflation that resulted in reduced economic growth. Against that backdrop, we then can describe the changes in national economic conditions and in the international oil market that are setting the stage for an upturn in electric load growth.

During the 1970s, unstable fiscal and monetary policies, combined with sharp increases in the price of oil, contributed significantly to inflation and reduced economic activity. But, throughout the decade, and in both economic downturns, electric generation generally out-performed both real economic growth and total energy growth (Exhibit 1):

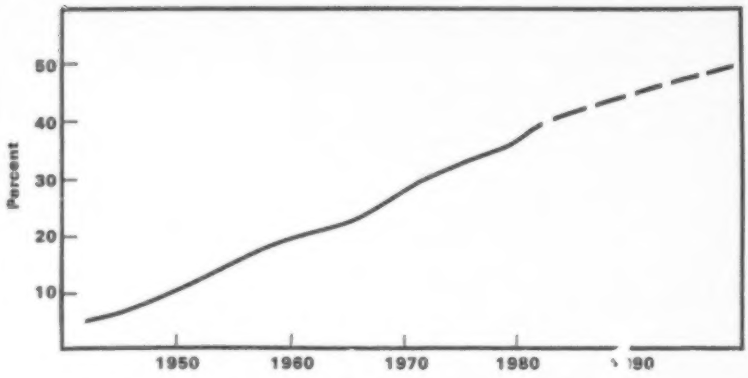
- While the weighted real increase in the price of energy between 1973–81 was about 160 percent, the real price of electricity increased only 50 percent;
- Economic recessions in 1974–75 and 1980–82 held average economic growth between 1972–83 to 2.2 percent;
- While total energy demand was essentially flat between 1972–83, electric sales grew at 2.5 percent per year.

Before the first oil price shock of 1973–74, post-war U.S. economic growth had averaged a healthy 4.2 percent per year. Primary energy and electric load growth also increased rapidly, and in the higher growth decade of the 1960s, grew annually at 4.5 percent and 7.5 percent respectively.

Because load growth exceeded primary energy growth, electricity captured a growing percentage of the U.S. energy market (Exhibit 2). The increased energy market share garnered by electricity was due to steady improvements in its relative economics vis-a-vis other energy sources and its reliability of supply.

The economic stability of the 1950s and 1960s ended abruptly when the world price of oil quadrupled, increasing from under $3 per barrel to over $12 per barrel. As shown in Exhibit 3, prices for all energy commodities rose significantly after this oil crisis. These rapid increases in energy prices, and the growing cost of federal government programs, were largely financed by significant increases in the money supply. These factors, combined with elimination of the then-existing price control program (energy excepted), led to near double-digit inflation rates from 1973 through much of 1975.

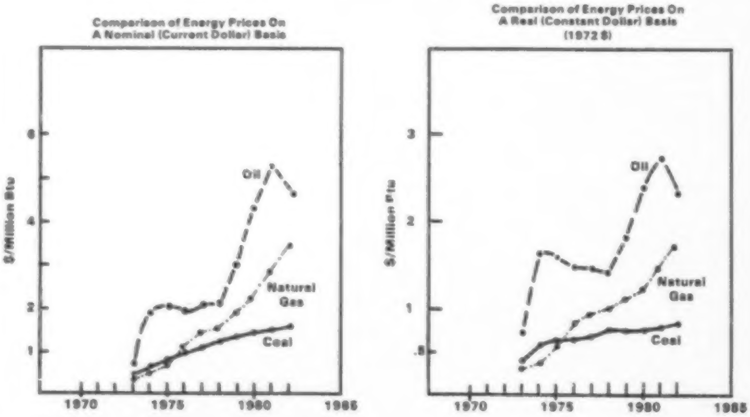
EXHIBIT 2
BECAUSE OF GREATER RELIABILITY OF PRICE AND SUPPLY, THE ELECTRICAL ENERGY FRACTION OF U.S. ENERGY REQUIREMENTS HAS INCREASED CONSISTENTLY OVER THE PAST 30 YEARS



Sources: DOE, *State Energy Data Reports*, 1980; DOE, *Monthly Energy Review*, January 1981; Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry, 1979;* ETA-Macro Projections.

$$\text{Electricity Fraction} = \frac{\text{Energy for Electricity Production}}{\text{Total Energy Requirements}}$$

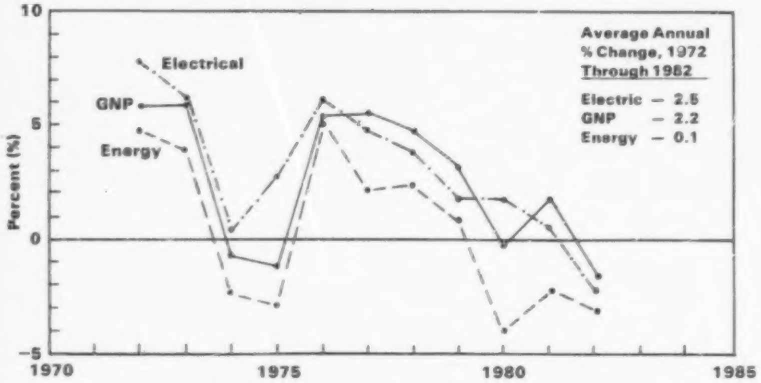
EXHIBIT 3
COMPARISON OF NOMINAL AND REAL PRICES OF PRIMARY ENERGY SOURCES



Natural Gas — Average price of gas delivered to utilities.
Oil — Average price of residual delivered to utilities.
Coal — Average price of fuel delivered to utilities.

Source: DOE, *Monthly Energy Review*.

EXHIBIT 4
ENERGY AND ELECTRICAL GROWTH
(Average Annual % Change)



Sources: Energy and Electric Use: DOE, *Monthly Enargy Review*, (1973-1982); GNP: Economic Report of the President; President's Council of Economic Advisors.

These developments caused a contraction in economic activity for both 1974 and 1975 when real GNP fell by 0.1 percent and 1.1 percent respectively. Corrective fiscal and monetary policies were instituted, resulting in a sharp drop in the rate of inflation beginning in late 1975. Nevertheless, the price for achieving this reduction in inflation was a sharp drop in economic growth. Total energy use also fell in 1974 and 1975 by 2.3 percent and 2.9 percent respectively. But, electric load growth maintained its historic relationships to energy and economic growth by increasing 0.3 percent in 1974 and 2.3 percent in 1975 (Exhibit 4). This growth reflected the growing substitution of electric energy for non-electric energy.

The sharply reduced inflation rates achieved in 1975 and 1976 set the stage for the economic growth which occurred from late 1975 into 1979. Economic growth and energy and electricity production also rebounded sharply, although at reduced rates relative to pre-1974 historical norms. Economic growth averaged 3.8 percent annually, and energy and electric consumption increased by 2.8 percent and 4.2 percent respectively.

However, inconsistent government economic policies in the late-1970s would contribute to a second severe economic contraction. Government spending increased at a rapid rate as domestic spending and entitlement programs expanded. The cost of these programs was paid for by once again monetizing the federal debt and increasing taxes by allowing inflation to push wage earners into higher tax brackets. The result was a higher rate of inflation and disincentives to save and invest. Also businesses were reluctant to make long-term capital investments due to heightened uncertainty and a growing inability to generate capital.

In addition, oil and gas price and allocation controls were maintained. In late 1975, Congress had legislated the extension of oil price controls through 1979. Further, the Federal Energy Administration was instructed *to lower* the price of domestic oil in February 1976. As W. Tucker relates, "It was Congress' election-year present to the nation for 1976. It worked well . . . consumers were already celebrating by surging back to big cars, and guzzling gas again as if the boycott had never happened. Everything seemed fine. Yet the oil price controls remained a time bomb ticking away in the American economy."[1] Combined with increasing inflation, price controls reduced the real price of energy; thus, the United States was once again ill-prepared to adjust to another energy shock. The stage was set for a second severe economic decline.

A near tripling of world oil prices in 1979–80 contributed once again to higher commodity prices, sharply higher inflation rates, and a sharp downturn in economic activity. The depth of the 1980–82 recession was evidenced by the fact that the overall industrial utilization index fell to its lowest point since the Commerce Department began tracking the index in the 1940s. For example:

- Auto industry output fell to a 24-year low;
- Steel industry utilization fell below 30 percent; and,
- Housing starts fell to a 36-year low.

Between 1979 and 1983, there was no real growth in the U.S. economy. Total energy use fell sharply, averaging a negative 2.9 percent. During this period, electrical generation, like the economy, was essentially flat (Exhibit 1).

The Economic Environment of the 1980s and the Role Electricity Will Play

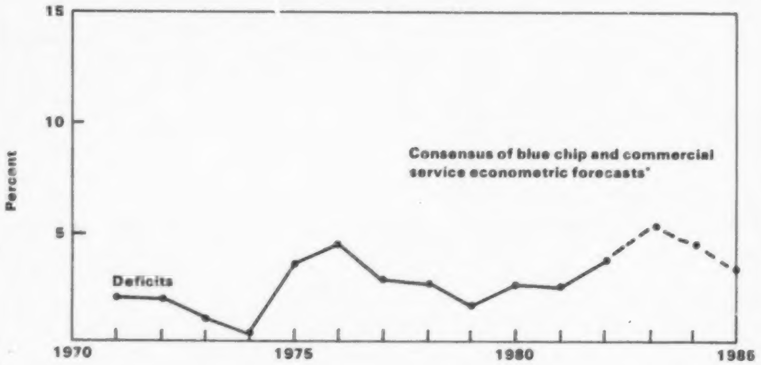
After three years of no growth, the U.S. economy appears poised for recovery in 1983, although the extent of the recovery expected varies from forecaster to forecaster. As of early 1983:

- The Reagan team was predicting average real growth of about 4 percent for the balance of the 1980s—about 3 percent in calendar 1983, followed by annual growth of about 4 percent thereafter;
- The House Budget Committee reported a "Blue Chip" forecast from business economists of 4 percent annual GNP growth for 1983 and 1984 and an average forecast from major commercial services of 4.5 percent for those same years.[2]

In contrast to the Administration's forecast of 3 percent in 1983, many economists expect a more robust recovery. For example, Boston's H. C. Wainright and Co., who correctly predicted the 1981 recession, now look for real growth to exceed 6 percent in 1983. Although this forecast is far from a consensus view, the recent stock market rally also suggests that 1983 growth rates may be higher than 3 percent. In fact, a number of economists, including Nobel laureate Paul Samuelson, have suggested that Administration economists are deliberately underestimating the extent of the potential recovery to force Congressional action on the perceived deficit issue.

The biggest uncertainty in the timing and size of future economic growth appears to be the deficit situation and its impact on interest rates. It is not clear, however, whether large deficits result in either inflation (and, therefore, high interest rates) or recessions.[3] In fact, on a full employment basis, the structural deficit problem all but disappears.[4] Further, the deficits projected by the "Blue Chip" and commercial services forecasts reported by the House Budget Committee are not extraordinary by historic standards (Exhibit 5). In addition, concerted efforts are underway in the Congress to reduce these potential deficits via new spending cuts and selective tax increases, and the Administration's proposed 1984 budget contains provisions for contingency tax increases.

EXHIBIT 5
FEDERAL DEFICITS AS A PERCENT OF GNP



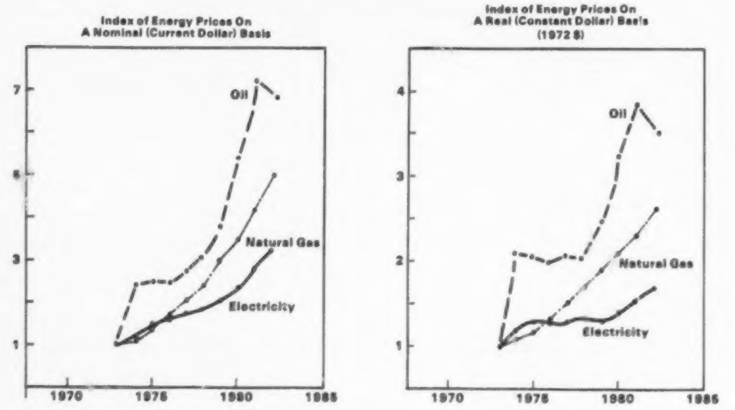
*Average of Data Resources, Chase Econometrics, Wharton EFA, Inc. and Major Business Economists.

Source: Extrapolation from "President Reagan's Fiscal Year 1984 Budget", House Budget Committee, February, 1983.

In any case, history indicates that these projections for economic recovery following a recession and its associated deficit run-up are, at minimum, reasonable. In fact, as projections for initial economic growth following a period of recession, they are low by historical standards, especially given current business conditions. Reagan's estimate of 3 percent for 1983 compares with 5.7 percent following the 1975 recession and 5.9 percent, 5.8 percent, and 6.7 percent following the 1965, 1962, and 1958 recessions. And, the Administration's estimate of 4 percent for the 1983–86 period compares with a 4.7 percent average for the 1976–79 period following the first oil-enhanced inflation/recession of the 1970s.

Moreover, there is growing evidence that a positive business environment —markedly more favorable than the volatile conditions of the past ten years—is emerging as a result of the partial implementation of the President's Economic Recovery Program (ERP). Thus far, the tangible benefits of the ERP have been slowing money supply growth and reducing inflation. The latter, which was under 4 percent in 1982 and is estimated at about 4 percent for 1983, should provide the stable conditions under which economic growth can be sustained. While the Tax Equity and Fiscal Responsibility Act (TEFRA) of 1982 reduced some of the incentives

EXHIBIT 6
COMPARISON OF NOMINAL AND REAL PRICES OF RETAIL U.S. ENERGY SOURCES



Natural Gas — Price is average of residential heating gas.
Oil — Price is average of home heating oil.
Electricity — Price is average of residential, commercial and industrial charge.

Source: DOE, *Monthly Energy Review.*

contained in the Economic Recovery Tax Act of 1981, significant tax benefits remain to businesses and consumers. When combined with a gradual decline in interest rates, the reduced tax burden should provide further incentives to stimulate economic growth. Implemented in October of 1981, the Tax Act should begin to have a real and sustained effect by early 1983.

Lastly, it appears that many economic forecasters have significantly overestimated real changes in the price of energy. For example, in its mid-1982 update on the economy, the Congressional Budget Office assumed weighted real increases in the price of energy resources of about 4–6 percent. They assumed crude oil prices, the average of domestic and world, would continue flat in 1983 and increase at a rate about equal to inflation thereafter. Also, natural gas prices were assumed to rise in real terms per the Natural Gas Policy Act. The Reagan team is also assuming real increases in the price of energy.

It is more likely, however, that real prices for energy resources will either remain constant or trend down through at least the mid-1980s, providing an additional stimulus to economic recovery. This condition should result from either a stabilization or gradual decline in real crude oil prices through the mid-1980s.[5]

Additionally, there is doubt whether natural gas prices can continue their recent upward price trends beyond 1983. For example, one more year of the recent oil and gas price trends for fuel delivered to utilities (Exhibit 3) would place gas prices about 10 percent above oil prices. This is unrealistic, however, as most energy analysts expect gas prices to clear 5–10 percent below oil prices.[6]

In any case, the real change in the weighted price of energy resources compares favorably with the approximately 160 percent real increase which occurred between 1973 and 1981. Because energy comprises 15 percent of inflation indices, the decline in energy prices will contribute to reduced inflation and a positive economic environment.

In summary, we feel there is basis for projecting sustained economic growth at annual levels of approximately 3.5–4.0 percent beginning in 1983.

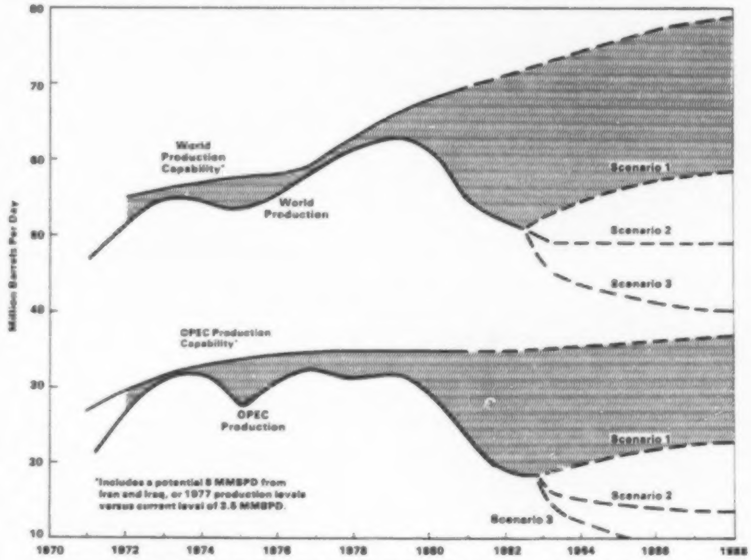
Paul Volcker also offers a positive view of the 1980s. As reported in an April, 1982, edition of the *Wall Street Journal*, Mr. Volcker sees "A reasonable prospect" that the 1980s will be "a sort of mirror image of the 1970s," with a reversal of the trends of the past decade. "Instead of a decade of rising inflation, we should see a decade of falling inflation. Instead of a decade of declining productivity growth, we should see a restoration of growth."

Electric growth's historical record for exceeding economic growth argues, in turn, for load growth in the 4–5 percent range. There is good reason why load growth should continue to outperform the total energy and economic sector.

First, *the price of electricity is positioned more favorably with respect to oil and natural gas prices than at any point in the 1970s.* The comparatively favorable price position of electricity will enhance its competitiveness with oil and natural gas in industrial processes, space and hot water heating, and transportation (Exhibit 6).

In fact, trends that suggest electricity is penetrating traditional oil and gas markets are already appearing. For the first three quarters of 1982, concurrent with the worst recession in over 40 years, residential and commercial electric sales were up 2.7 percent over 1981. And in separate speeches in 1981 and 1982 respectively, the presidents of Bal-

EXHIBIT 7
THE PRESENT SURPLUS IN WORLD AND OPEC OIL PRODUCTION CAPABILITY GREATLY EXCEEDS THAT WHICH FOLLOWED THE 1973 OIL CRISIS



*Includes a potential 8 MMBPD from Iran and Iraq, or 1977 production levels versus current level of 3.5 MMBPD.

Sources: "World Energy, The Facts and the Future," D. Hedley (1981); "Energy and the Developing Nations," proceedings of EPRI Workshop, Hoover Institution, Stanford University, P. Auer (1980); "DOE Monthly Energy Review"; *Economist*, March 27, November 20, and December 11, 1982.

timore Gas & Electric Co. (George McGowan) and Virginia Electric & Power Co. (William Berry) stated that while only 10–12 percent of existing homes in their respective service areas had electric heating, about 80 percent of all new homes were installing heat pumps.

Second, real electricity prices, which have risen by 50 percent since 1973, should increase much more moderately in the 1980s. Uranium, coal, oil, and hydro comprise more than 80 percent of utility energy requirements, and these fuel forms are expected to decline in price in real terms or increase in price at a rate only equal to inflation. Also, lower inflation and a gradual reduction in interest rates should reduce construction cost increases and the rate levels needed to sustain capital expansion programs.

Thus, we feel that electrical demand may be poised for a period of sustained growth and is being underestimated by utility planners.

Oil Prices: Less of a Factor in the 1980s

Because the two oil price shocks of the 1970s played significant roles in reducing economic and electric growth, it is important to understand why these conditions are not expected to recur in the 1980s. Exhibit 7 depicts the consumption trends—initiated in 1979, when oil prices rose to $34/barrel—that have resulted in the current "oil glut." For example:

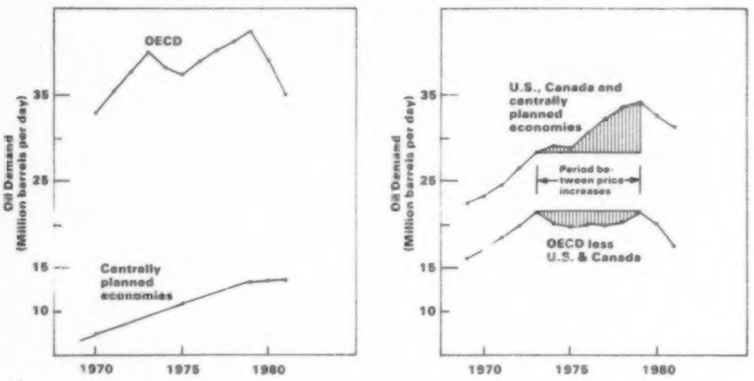
- Free world consumption has fallen about 20 percent in the past two years from 49 to 40 million barrels per day; OECD consumption has fallen similarly, from 42 to 35 million barrels per day;
- U.S. consumption has fallen from 18.8 to 15.8 million barrels per day; and in March 1982, imports of crude oil were running at a nine-year low;

The fall in world oil demand has been absorbed primarily by OPEC. Since 1979, OPEC production has fallen by nearly 50 percent, from 31 to under 19 million barrels per day. Not surprisingly, the price of oil has begun to erode with spot markets trending well below $30 per barrel. These trends are projected to continue in the near- and mid-term.

- The swift 1979 run-up in prices to $34 per barrel put into motion a number of structural changes in the international oil markets. Capital investments have been, and are still being, made which will reduce oil use. Examples include the conversion of the Japanese steel industry from oil to coal, the wide-scale introduction of more fuel-efficient cars in the U.S., and the billions of dollars which have been invested in insulation.[7]
- Consumption of oil in the USSR and Eastern Bloc nations is expected to fall as a result of recent Soviet decisions to reduce subsidies on oil products. Up to this time, oil deliveries to Eastern Europe have been subsidized at about one-third below market value. Increased oil prices in Eastern Europe will certainly drive consumption down, and according to some, reduce economic growth and move a number of countries to the brink of economic insolvency.[8]

Over the near-term, oil producers may be forced to further reduce prices in efforts to increase revenues to meet credit requirements. OPEC nations, including Saudi Arabia, could shortly become cash guzzlers on the international credit markets, or face a sharp curtailment in their domestic develop-

EXHIBIT 8
COUNTRIES WITH PRICE CONTROLS DOMINATED THE INCREMENTAL DEMAND FOR OIL BETWEEN 1973-1979



Sources: "World Energy, The Facts and the Future," D. Hedley (1981); "Energy and the Developing Nations," proceedings of EPRI Workshop, Hoover Institution, Stanford University, P. Auer (1980); DOE, *Monthly Energy Review; Economist*, March 27, 1982.

ment programs. For example, in early 1982 with oil at $34 a barrel, Saudi Arabia needed to produce 6.3 million barrels a day to maintain its internal development program. At $27 a barrel, and adjusting for inflation, oil production of 8.5 million barrels per day will be required in 1983. This compares with recent reports of Saudi production of under 5 million barrels a day. Overall, Morgan Guaranty recently predicted that at $29–30 a barrel, OPEC would go from a cash surplus of $105 billion in 1980 to a $20 billion deficit in 1983.

But what is the long-term outlook? As the world recession ends and economic growth recovers, will oil consumption accelerate, the oil market tighten, and prices spiral upward once again as in 1973 and 1979? We think that oil prices may begin trending up in the late 1980s, but the oil price explosions of 1973 and 1979 will not be repeated. Why? *Structural differences exist between the international oil markets which followed the 1973 and 1979 oil price explosions:*

- The relative price position of oil is significantly higher today than after the post-1973 price perturbation (Exhibit 6). Thus, world oil demand is falling in part because market economies are reacting to $34-a-barrel oil. In 1982, in constant dollars:
  —World oil prices were 80 percent higher than in 1974;
  —In the U.S., average refiner acquisition costs were 140 percent higher than in 1974.

  Indeed, while OECD use of oil has fallen nearly 20 percent since 1979, OECD economic growth has been slightly positive. And since 1977, Japan has experienced an overall increase in GNP of 20 percent, while oil consumption has dropped by 10 percent. As economic growth returns, it is unlikely that industry, having invested capital in new equipment, will discontinue the use of more efficient industrial processes or coal handling equipment. Nor will consumers trade in fuel efficient cars or remove insulation.
- Unlike the post-1973 environment, *price controls no longer exist on oil in the U.S.*, which consumes nearly one-third of the world's oil. And, as noted above, the USSR has decided to stop subsidizing the price of oil internally, as well as in Eastern Bloc countries. The importance of this oil "deregulation," when compared to the 1973–1979 period, is best seen in Exhibit 8. Between the peaks of 1973 and 1979, world oil consumption increased by about 6.5 million barrels per day. However, in the U.S., Canada, USSR, and Eastern Bloc countries—which all had price controls that maintained domestic oil prices below world prices—consumption grew by 5 million barrels per day, about 80 percent of the total. Discounting Canada and the U.S., oil consumption in the OECD nations was unchanged between 1973 and 1979.
- Non-OPEC production continues to grow. Since the first oil crisis, oil production—much of it in non-OPEC nations—has been climbing steadily at about a 5 percent annual rate. Based on existing explorations, oil discovery, and investments, this growth appears sustainable over the next few years. The projected 7 million barrel per day additional capacity between 1982 and 1987 shown in Exhibit 7 comes mainly from Mexico, Norway, U.K., and Africa.
- Longer lead-time capital investments planned after the first oil price increase only now are beginning to influence the oil market. An excellent example is France's

nuclear program, which helped reduce French oil use in 1981 by 18.2 percent.

Returning to Exhibit 7, we feel that for any plausible oil scenario, there should be a substantial surplus of supply over demand, with OPEC continuing to operate considerably below capacity.[9] This scenario is independent of any return to normalcy in Iran and Iraq, and a full re-offering of their oil into world markets.

Prices should stabilize or trend down through the mid-1980s as suppliers noted for their differing political stances attempt to allocate a declining export market. The March, 1982, OPEC decision to hold prices by cutting production to 17.5 million barrels per day suggested an indifference to market forces that had reduced world oil consumption by nearly 20 percent since 1979. The decision was followed by discord as many OPEC members violated production quotas, largely through price discounting. A similar January, 1983, decision to limit production likely will fare no better. As long as OPEC attempts to hold the $34 price, demand will continue to fall. Only when prices fall significantly will the incentive to invest in conservation and alternative fuel consuming technologies be reduced.

The Potential Size of the Underforecast

Although economic conditions are projected to change significantly from those which persisted over the last 10 years, load forecasters are not altering their electricity projections. As can be seen from the data presented in Exhibit 9, both peak and energy load growth projections presently approximate 3.0 percent. And instead of being adjusted upward to reflect potential economic growth, load forecasters have continued to reduce their projections. For example, the NERC information contained in Exhibit 10 could have been reproduced for each study projection identified in Exhibit 9, and the results would have all been similar.

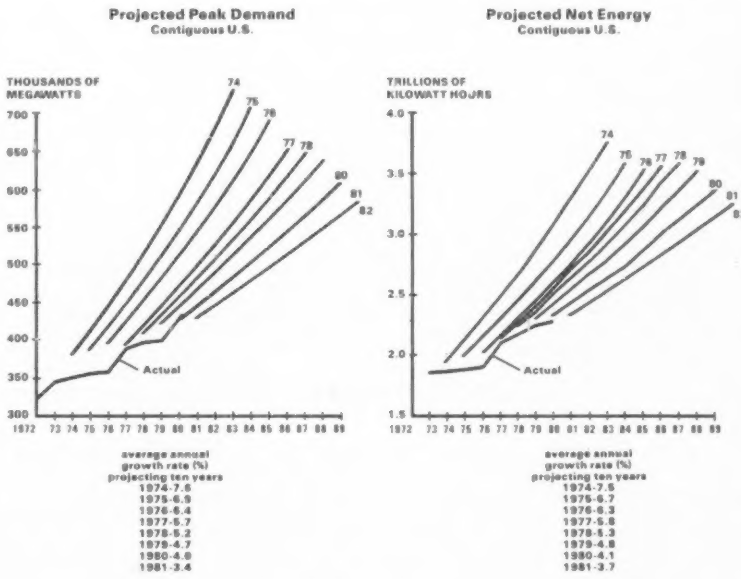
Even these projections are felt by many to be an overstatement of future electricity growth. Some utilities in the Midwest, for example, have recently lowered their official peak load forecast from 3 percent per year to 1 percent per year. New England and Middle Atlantic utilities generally show load growth projections of no more than 1 percent per year. While the faster growing Sunbelt regions are projecting more rapid rates of load growth than the rest of the country, the forecasted increases in load have been significantly scaled back from earlier estimates. And, as stated earlier, there is a continuing tendency on the part of load forecasters to reduce, not increase, their projections.

EXHIBIT 9
PROJECTED AVERAGE ANNUAL RATES OF ELECTRICITY GROWTH BETWEEN 1981 AND 1990

Source of Forecast	Generation	Peak Load
NERC, August 1982	3.3%	3.0%
ELECTRICAL WORLD September 1982	2.9%	2.8%
DOE/NEPP, 1981	3.06%	N/A
DOE/EIA, 1980	3.11%	2.89%
WHARTON, October 1981	3.76%	N/A
DRI, Autumn 1981	2.99%	2.56%

EXHIBIT 10
CHANGES IN THE NATIONAL ELECTRIC RELIABILITY COUNCIL'S GROWTH PROJECTIONS

Projected ten year growth continues to slow . . .



But, given the potential for sustained improvements in economic and financial conditions, why are load growth projections continuing to decline?

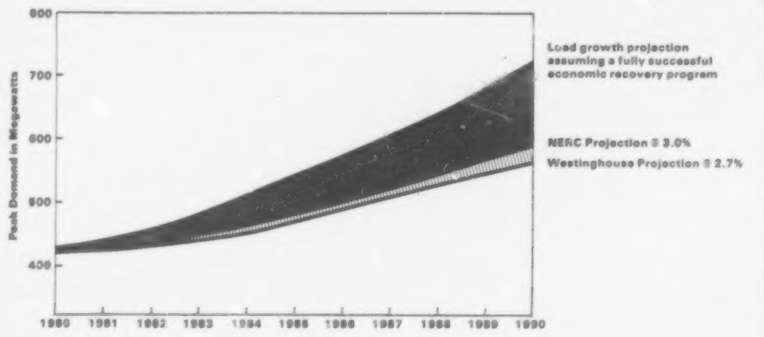


EXHIBIT 11
POTENTIAL IMPACT ON NATIONWIDE UTILITY LOAD GROWTH OF ERP ECONOMIC ACTIVITY ASSUMPTIONS

Of course, load forecasters undoubtedly are building conservation and load management effects into their forecasting models. While building conservation and load management assumptions into load forecasts is desirable, however, at present it is not clear how this is done. Frequently though, it is done by simply shaving between 0.5 and 2 percentage points off the annual growth rate.

Quantifying these results is likely to become a more difficult task if economic conditions improve and consumers seek ways to use additional amounts of electricity. In fact, the quantification process has already been made more difficult by the rapid run-up in real oil prices. The run-up in natural gas prices, which is occurring now as a result of deregulation, will further complicate this process by increasing the economic attractiveness of electricity. It is not clear how load forecasters have incorporated these price effects into their load growth projections. And under more rapid economic growth conditions, previous conservation and load management assumptions may be thrown into disarray. Moreover, consistently poor performance of end-use forecasting models in the early 1970s argues against overemphasis of their current predictions.

Aside from questions of how to forecast conservation, however, electric load forecasters appear to be pessimistic regarding the outlook for a sustained economic recovery—despite the fact that many government and private sector economic forecasters are predicting significant economic growth beginning in 1983. While the jury is still out on the current administration's program, electric load forecasters appear to have discounted its potential benefits. This assumption may come back to haunt utilities if economic growth gradually accelerates, just as the optimistic load forecasts they made during much of the 1970s have recently haunted them with "over capacity" and expensive plant cancellations.

Exhibit 11 illustrates the potential size of the underforecast. Included are current utility and non-utility projections and projections we believe to be consistent with the long-term economic conditions projected by the administration. As is clear from the exhibit, the difference is significant. Assuming both a successful economic recovery program and a continuation of the recent relationship between economic growth and electricity consumption (as illustrated in Exhibit 4), load growth could:

- Approximate an average annual rate of 5 percent per year;
- Result in a 1990 peak demand of 700,000 megawatts. This compares with a current peak demand of approximately 440,000 megawatts and a currently forecasted 1990 peak demand of less than 600,000 megawatts.

While the exhibit cannot be taken at face value, it does indicate the possibility that utilities may be underforecasting and the potential size of the underforecast.

Potential Implications of Underforecasting

While planned and partially completed power plants have been delayed or cancelled for both financial and institutional reasons, present capacity expansion plans are at least partially reflective of the utility industry's official load growth projections. As of mid-1982, utilities were projecting the installation of the following capacity by 1992:

- About 70,000 megawatts of additional nuclear capacity;
- Over 90,000 megawatts of coal-fired generation capacity;
- Approximately 10,000 to 20,000 megawatts of combustion turbines, hydro, geothermal, and other alternative forms of generation.

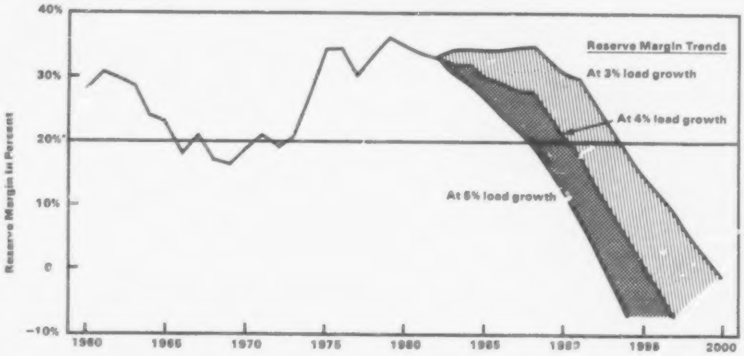
Although recent nuclear plant cancellations probably have reduced the total, utility reserve margins should be ample for the mid-term if present utility load growth projections are realized. For example, Exhibit 12 contains a projection of national reserve margin trends for the remainder of this century, assuming:

- An average annual growth rate in summer peak demand of 3 percent, 4 percent, and 5 percent; 3 percent growth assumes a continuation of recent historic trends, 4 percent growth assumes conditions consistent with partial economic recovery, and 5 percent growth assumes a fully successful economic recovery program.
- Capacity installation during the 1980s in the approximate amounts described above.

The results of this graph suggest that at a 3 percent rate of load growth, reserve margins would be adequate through the early 1990s. If load growth of less than 3 percent is realized, a condition many load forecasters predict, reserve margins would appear to be adequate through the mid-1990s.

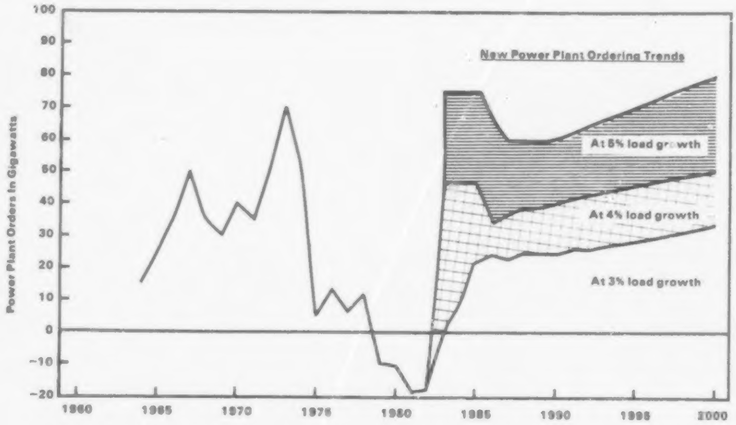
But upon closer examination, we believe these reserve margins to be illusory. First of all, it can be argued with strong justification that currently projected reserve margins erode considerably when regional disparities, the vintage of existing plant, the potential for additional nuclear plant cancellations, and the existence of large quantities of economically obsolete oil- and gas-fired generating units are taken into account. We will not argue the pros and cons of these positions, but only note they support the notion that projected reserve margins are not as adequate as they appear to be on paper.

EXHIBIT 12
RESERVE MARGIN TRENDS AND PROJECTIONS
(All Figures Are In Percent)



*Historically, a national reserve margin of approximately 20% has been identified as that which is consistent with reliable electric service. For some regions a reserve margin as low as 15% and as high as 25% may be more appropriate, reflecting regional grid capabilities and peaking phenomena.

EXHIBIT 13
POWER PLANT ORDERING TRENDS AND PROJECTIONS*



*Projections of plant orders assume a 10 year licensing and construction lead time, maintenance of a 20% capacity reserve margin, and no plant retirements.

When the potential impact of any sustained economic recovery is factored into the analysis, earlier projected reserve margins all but disappear by 1990 (Exhibit 12). Using the high load growth rate described earlier, the 1990 reserve margin of approximately 25 percent declines to less than 10 percent. Only if annual electric load growth averages 4.0 percent or less over the remainder of the decade will a nationwide reserve margin of 20 percent be maintained. For the early 1990s, the picture is more tentative, given recent nuclear plant cancellations and the 10-year lead time needed to bring a power plant on-line.

The obvious conclusion to draw is that in the not too distant future new capacity requirements will increase significantly, expanding the market for coal, nuclear, and other forms of generation. This, in turn, would provide needed business to equipment manufacturers, fuel and other vendors, architect engineers, and other components of the electric infrastructure.

Exhibit 13 shows that beginning in the early to mid-1980s, utilities must begin ordering significant amounts of new capacity if a nationwide 20 percent reserve margin is to be maintained:

- Under 3 percent load growth, an average new plant ordering rate of 25 GWe per year is required in

1984, gradually increasing to 35 GWe by the year 2000;

- Under 4 percent load growth, an average ordering rate of 40 GWe per year is required in 1983, increasing to over 50 GWe by the year 2000;
- Under 5 percent load growth, an average ordering rate of 70 GWe is required in 1983, gradually increasing to 80 GWe by the year 2000.

For these scenarios, we have assumed a ten-year lead-time and *no plant retirements.* These ordering rates compare with the effectively zero ordering rate of the past eight years. Put another way, *the power business has been in a recession for nearly a decade. Liquidation of inventory—$1-to-2-billion power plants—has been chronic as construction programs predicated on 7 percent load growth fell victim to the economic upheavals of the 1970s and the resulting 3 percent load growth.*

But there is a less obvious and potentially more dangerous implication to be drawn from this analysis. The electric utility industry is implicitly assuming that a sustained economic recovery will not occur, or that the historical relationship between economic growth and electric load growth will be so altered that even under rapid economic growth conditions load will not increase significantly. Or, one could conclude that the utility industry is simply marking time until economic conditions stabilize and future electricity requirements become better defined.

However, this stabilization process could take at least another year or two to complete, and utility management may not begin believing the results until another year or two after that—1985. If this time is allowed to pass without addressing and resolving the fundamental financial, power plant licensing, and other supply planning problems presently affecting the industry's decision-making process, new capacity may not be brought on fast enough to prevent the reserve margin deterioration previously described. If this deterioration occurs:

- The cost of electricity will almost certainly increase rapidly as uneconomic and inefficient sources of power are used;
- The reliability of service may deteriorate as brownouts are instituted to allocate limited supplies among increased electric energy needs; and
- Electricity markets may be forfeited to other energy forms which serve end-use applications less efficiently and are of a higher cost.

The unavailability of economic and reliable supplies of electricity will almost certainly act as a constraint to economic growth and may force business and industry to expand their operations elsewhere.

Finally, the utility industry itself may pay a severe price for allowing itself to be overtaken by events. Severe problems, such as brownouts, high power costs, and a constrained economy, typically require immediate and radical solutions. In the past, these radical solutions—such as price controls and government mandated allocations in response to the 1973 and 1979 oil supply disruptions—have done more harm than good. The utility industry and its customers should not expect to be exempt from similar treatment. Further, it is easy to envision the ordering and construction of combustion turbines and other short lead-time, low capital-cost equipment under the mid- and high-growth scenarios outlined above. In the 1960s and 1970s this condition happened more than once. This capacity would clearly be of a high operating cost nature, requiring consumers to pay significantly higher cost than necessary, and result in less reliable service. In addition, the institutional, regulatory, and financial problems of the utility industry would not be resolved in an optimum fashion under such conditions.

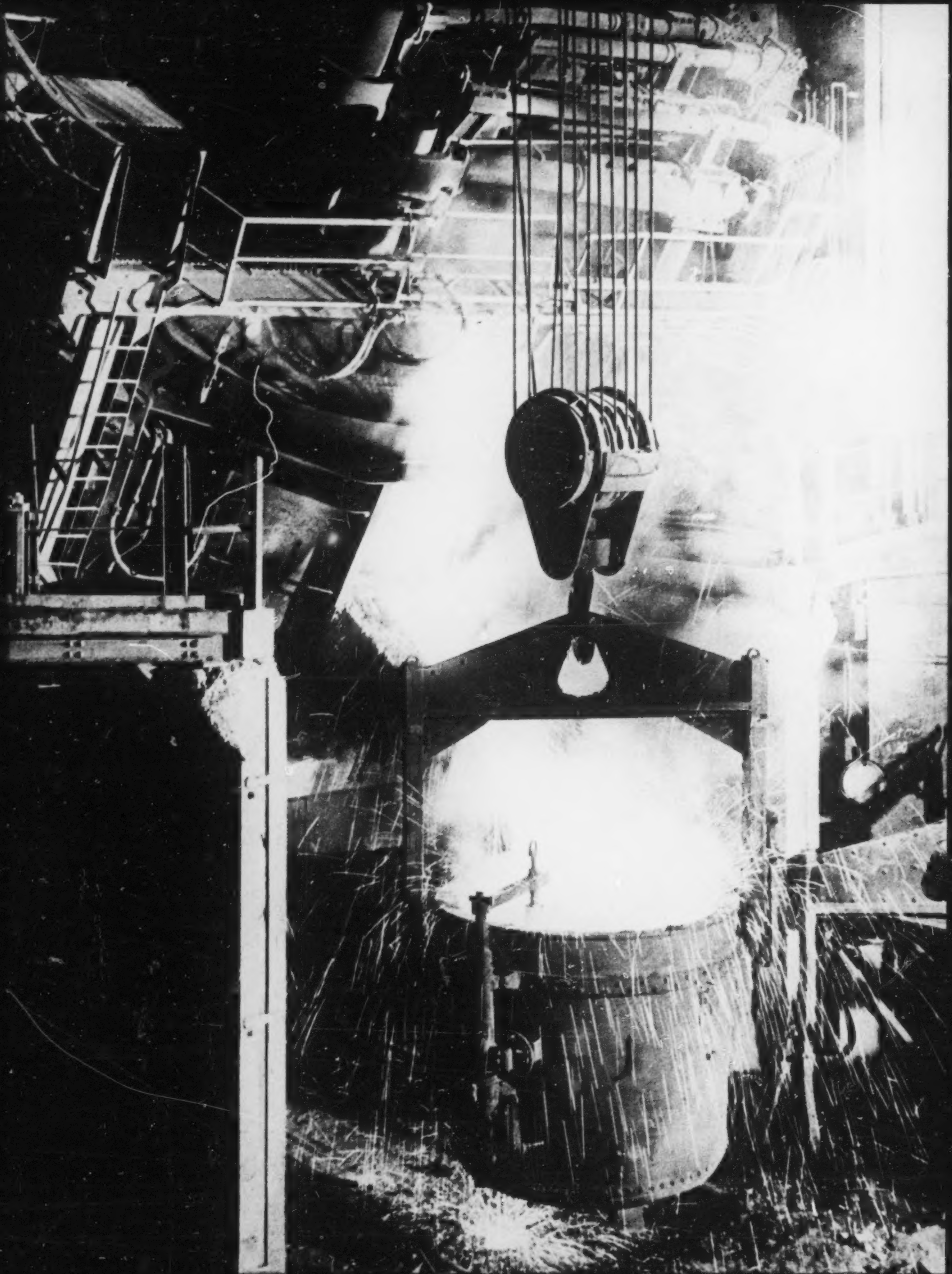
Closing Thoughts

In closing, we return to Will Rogers who once mused: "Even if you're on the right track, you'll get run over if you just sit there." This may apply to the electric utility industry should its decisionmakers incorrectly anticipate the economic climate of the 1980s. In which case, the use of electricity—which has proven to be the "right track" for U.S. economic growth since 1945—could peak for reasons other than its inherent economics vis-a-vis other energy sources. Further, if the electric industry's generating capacity is ever inadequate, the public will be even less sympathetic toward the industry's dilemma than it is now toward the industry's "excess-capacity" problems.

In summary, we have argued that load forecasters appear to be basing future load growth on a continuation of the economic conditions which have characterized the past decade. We feel that such assumptions are not prudent and that they ignore longer term trends concerning the U.S. use of electricity. Instead, we believe both the utility industry and its stakeholders should recognize that underforecasting load growth is possible under today's rapidly changing economic conditions, with potentially serious impacts on reserve margin and the cost and reliability of electric service. Unless the utility industry comes to grips with the financial and regulatory issues that have constrained the timely and cost-effective addition of new generation, the solutions eventually proposed for the capacity shortfall may be drastic, inefficient, and costly. And, in any case, the need to order plant capacity exists today because the backlog of capacity that existed in 1973 is gone (considering 10-year lead times). When the ordering begins, as it will, the power business will begin to prosper again.

Notes

1. For a fuller treatment of price controls and world oil markets, see William Tucker's "The Energy Crisis Is Over," *Harper's*, November 1981.
2. *President Reagan's Fiscal Year 1984 Budget, A Summary and Analysis Prepared by the Staff of the House Budget Committee*, February 1983.
3. See, for instance, H. Stein's "Deficits Are Not Depressing," *Wall Street Journal*, January 12, 1983.
4. See Paul C. Roberts op. ed. piece in the December 21, 1982 *Wall Street Journal*.
5. Because oil represents about 40 percent of the U.S. energy picture, a stabilization or fall in crude oil prices would likely offset real increases in natural gas prices. The possibility of a 30–50 percent drop in real oil prices has been described, for example, by W. M. Brown, "Can OPEC Survive the Oil Glut," *Fortune*, November 30, 1981.
6. "The Rise and Fall of Regulation in the Natural Gas Industry," A. R. Tussing and C. C. Barlow, *Public Utilities Fortnightly*, March 4, 1982.
7. For example, U.S. consumption of gasoline fell about 10 percent in the last two years, from 7.25 million barrels per day in 1979 to about 6.6 million barrels per day in 1981. Because the U.S. auto fleet turns over about every 10 years, the full impact of more efficient automobiles will not be felt until 1985-87, by which time domestic gasoline consumption could drop another 1–1.5 million barrels per day.
8. From a study by the Central Intelligence Agency, cited in the *Wall Street Journal*, February 11, 1982.
9. The demand projections in Exhibit 7 are only intended as representative scenarios highlighting the oil supply-demand mismatch. Scenario 1 assumes demand responses similar to those following the 1973–75 period, but without the upward pressures caused by the oil price controls that characterized the post-1973 oil crisis. Scenario 2 assumes continuation of the 1980–82 trend with a 6 percent decline in oil demand in 1982 and demand flat thereafter. Scenario 3 assumes a drop in OECD consumption to 20 MBPD by 1990 from 35 MBPD in 1981 as suggested by S. F. Singer in "What is Happening To World Oil," *Wall Street Journal*, March 10, 1982. Any scenario would clearly be influenced by market forces, e.g., a halving of world oil prices could result in demand above Scenario 1 and potentially contribute to an eventual tightening of world oil markets.



The Promise of Neoindustrialization

By Mary H. Wayne

Innovative electricity-based technologies ultimately may transform the very nature of work—and life itself—in the United States

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Much as a severe wood shortage prompted the development of coal-based technologies in the early 1800s and gave rise to that society-transforming phenomenon known as the Industrial Revolution, recent changes in the supply and price of raw materials are spurring the development of new electricity-based production technologies. In the first two parts of this three-part series on neoindustrialization, author Mary Wayne examined this similarity and explained why these emerging technologies may foreshadow a second revolution—a "neoindustrial" revolution. In this final article, she explores how such a revolution could transform society.

"Neoindustrialization" describes a new type of economic growth beginning to occur in the United States and other advanced nations. Accompanied by the soft hum of computers rather than the noisy hiss and clatter of steam engines, it promises to boost manufacturing output in ways that are quieter, cleaner, and far more efficient than earlier production methods.

The resource base of neoindustrial production is diverse. It moves beyond heavy dependence on fossil fuels and on the raw materials used in the past. Many neoindustrial technologies will be powered by electricity generated from a growing variety of power sources: not only from traditional fuels such as coal, but from renewable resources such as the sun, the wind, and the movement of water.

The new production methods are similarly diverse, especially those that are electricity-based. Many can be fine-tuned to their special applications. Industrial production methods in the future likely will display a flexibility that contrasts sharply with the unwieldy steam power methods of the industrial age.

Just as shifts in the resource base and in production methods have marked major socioeconomic shifts in the past, neoindustrial society may be quite different from the industrial society in which most Americans have grown up. To supply a framework for speculating about what may lie ahead, let us look back for a moment at the Industrial Revolution and the transformations it brought.

Features of Industrial Society

One of the first changes was the centralization of work under the factory system. To find gainful employment, people left their pursuits on the land and presented themselves at the place where the capital and the concentrated energy sources necessary to run high-volume industrial production came together: the factory.

This centralization of work in the factory led inevitably to centralization of life in the city. In all nations since England's early example, urban growth has been a direct consequence of industrial production methods. In a traditional industrial system, it has been axiomatic that labor, like capital and energy, must be concentrated in one place for production to occur.

Standardization was another consequence of industrial technology. The cheapest way to do things with these technologies was uniformly, and on a large scale. Both products and manufacturing methods became increasingly standardized as industry expanded. This uniformity eventually extended far beyond the factory, pervading styles of housing, dress, education, speech, and entertainment—in short, the entire industrial culture.

The need for concentration of capital meant those who had worked at home as independent producers under the preindustrial system of domestic manufacture could no longer do so. Access

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The very nature of blue collar work is expected to change in these new factories.

to ownership of the expensive new power machinery required wealth. Under such a highly capital-intensive system of production, most people were excluded; they had no choice but to become wage workers in the employ of those who owned the machines. This became a feature of industrial societies regardless of their economic or political structure—that is, regardless of whether the machinery belonged to individuals, to groups, or to the state.

A certain increase in environmental pollution was another inevitable consequence of the new production methods. Intensive burning of fossil fuels was so much a part of the industrial system that the belching smokestack came to symbolize prosperity. As soot-showering factories turned out more and better goods for the average citizen, most people seemed willing to accept some dirt as the price of progress. It was not until much later, during the 1960s, that environmental preservation became a major topic of public concern.

Industrial society, then, can be characterized very roughly in terms of these five broad tendencies: centralization of work in factories and other production facilities; urbanization of the population; standardization of products and procedures for large-scale production; exclusion of many would-be small producers from the system; and gradual pollution of the environment. Some observers believe that all these tendencies are likely to be challenged by the advent of neoindustrial society —by what various thinkers are calling "the technetronic age," "postindustrial society," or "the third wave."[1]

Already the arrival of a mature industrial economy has signaled certain shifts. Today's workers enjoy far more leisure than their nineteenth-century forebears did and still maintain a far higher standard of living. If we take the 1890 workweek as a standard, the modern worker can be viewed as receiving a four-month paid vacation every year. The average American workweek has fallen from nearly 62 hours in the 1890s to around 40 hours or less today. The result is about 1200 extra hours of free time per worker per year.[2]

What's more, people begin working later in life today, after years of extended schooling. And they have more leisure years in retirement. Producing goods and services, even at rising levels, no longer requires the full-time life-long effort it once did.

Part of the reason is a fundamental shift in the way work is accomplished. Back in the 1890s, 90 percent of all Americans still worked with their hands. Today, various estimates place that figure between 20 and 40 percent —in any case, a massive decline. According to management theorist Peter F. Drucker, "The substitution of knowledge for manual effort as the productive resource in work is the greatest change in the history of work. . . . This change is still in progress, but in the industrially advanced countries, especially in the United States, it has already completely changed society."[3]

The emergence of knowledge workers as the predominant type in the labor force of a mature industrial economy presages greater changes to come, according to author Alvin Toffler. He is among the futurists who foresee neoindustrial production methods promoting the evolution of radically new workstyles. He envisions major work changes occurring in the factory, the office, and—perhaps most important of all—the home.

The Factory of the Future

The factory of the future, in Toffler's view, will be very much like the high-technology Hewlett-Packard electronics production facility he visited in Colorado. This factory is staffed about 40 percent by knowledge workers: engineers, programmers, technicians, and managerial and clerical personnel. It is quiet and filled with greenery. The workers have flexible hours and dress as they wish on this very unusual factory floor.

"As I entered the building," Toffler writes, "I remembered again the factories in which I had once worked, with all their clatter and roar, their dirt, smoke, and suppressed anger. . . . My old companions in their heavy steel-tipped shoes, dirty overalls, and workingmen's caps would find it difficult, I believe, to think of the place as a factory at all."[4]

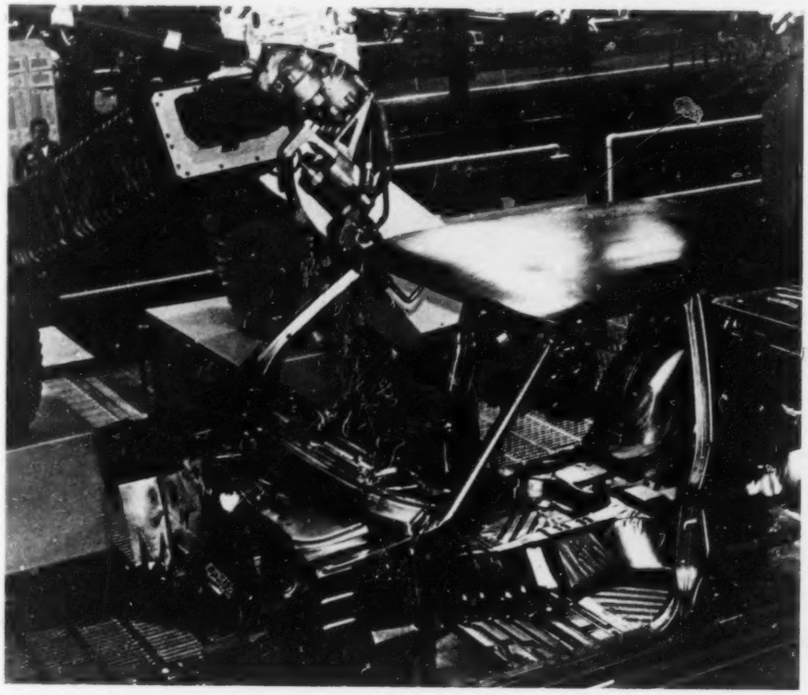
The very nature of blue-collar work is expected to change in these new factories. Physical strain and danger will be almost eliminated, but greater mental effort will be required. Gone will be the days when a worker could perform routine tasks with his hands while his mind was free for conversation or daydreaming. Operating and monitoring computerized control panels for industrial robots, which will do most of the heavy physical work, will call for advanced skills and intensified concentration. Even the factory production worker will thus become a knowledge worker.[5]

The trend in this direction received a recent push when IBM unveiled its new industrial robot system featuring a computer-controlled arm that can move in as many as six directions. The arm, mounted in a rectangular frame, is versatile in its applications. It has already been used to insert electronic parts into circuit boards, assemble mechanical parts for word processors and printers, drill holes in aircraft components, and test the wiring of large mainframe computers.[6] Furthermore, the computer's ability to integrate all the diverse operations involved in producing a particular item—say, a camera or a motorcycle—can transform conventional production methods. The computer can allocate resources, speed materials flow, and schedule operations, in addition to directing much of the actual production work.

But innovative manufacturing operations such as the Colorado plant are still rare in the United States. This is so despite the fact that much of the technology that makes these operations possible was first developed here. Foreign nations have taken the lead in applying new electrotechnology, especially computerized systems, to the manufacturing process.

A West German company that uses computer-integrated methods to produce titanium parts for Tornado fighter planes has been called the most advanced and flexible machine system in the world today.[7] About 75 to 80 percent of the cutting work is handled by machines, in contrast to the usual 15 to 30 percent in a conventional operation. And the plane is produced in 18 months rather than 30, with fewer machine tools and fewer skilled machinists required.

But most of all it is the Japanese who are forging ahead with new manufacturing applications in a way that has become increasingly worrisome to their American competitors. Several Japanese companies run their plants 24 hours a day, with only computer-controlled machines at work during the night shift. Further, some are close to perfecting computerized systems that can operate around the clock.



Factory work will become much less labor-intensive and much more knowledge-intensive. Industrial robots will man the production lines, and workers will operate and monitor the robots.

Whereas the conventional factory achieves only about 15 percent utilization of its capital equipment, the 24-hour unmanned system being developed by the Japanese is expected to provide utilization in the vastly improved range of 75 to 80 percent.[8]

The first patents for industrial robots were filed in the United States around 1954, but again, the Japanese have taken the lead in applying robot technology. By the early 1980s, Japan had roughly 14,000 programmable industrial robots in operation, compared with only 3500 to 4000 working in the United States. Japanese companies typically make their own robots, tailoring them to the needs of their particular manufacturing systems. For example, Yamaha makes arc-welding robots that work on its motorcycle assembly lines. Seiko makes robots that assemble watches. Pentel builds robots that put together felt-tip pens, and Okamura's robots assemble office furniture. These specialized robots are often sold to other members of the same industry once their usefulness has been established.[9]

An American management consultant who has studied Japanese industrial practices emphasizes the critical role of adapting new technologies—not only computers and robots, but lasers and the great variety of other manufacturing innovations—to American industry's very basic problems with productivity and cost control. "It's precisely in those . . . areas," says consultant Ira Magaziner, "that we in this country have been so weak—that is, in taking new inventions and applying them to existing industries for existing problems."[10]

Hughes Aircraft expects computer-aided design and manufacturing systems to increase productivity significantly—perhaps by as much as a factor of ten.

In the United States, several companies are offering industry the latest in applied electrotechnology: packages of factory automation products and services. For example, General Electric offers its new GEnet, a local communications network for signaling and data-sharing between computers and other electronics equipment, as "the spinal cord and central nervous system of an automated factory."[11] The slogan GE has been using to stir industrial customers is "automate, emigrate, or evaporate."

Hughes Aircraft Company, for example, is spending $240 million over the next five years on computer-aided manufacturing systems. This capital investment is part of a $1.5 billion program for expansion and modernization to improve productivity. According to Hughes, computer-aided manufacturing is improving productivity in the electronics business by as much as a factor of ten.

But market resistance in the United States to new capital spending for such systems has remained stiff, especially in a recessionary economy. The investment in existing systems is huge, and the risk of switching is substantial in terms of lost production time or uncertain product quality. The tendency has been to patch and upgrade conventional systems rather than risk investment in something new.

So the neoindustrial factory will probably come slowly to the United States, though many experts consider its eventual arrival inevitable. Meanwhile, electrotechnology on a smaller scale is penetrating the office environment at a rapid pace. The investment in new computers, word processors, optical scanners, and telecommunications systems is less costly than an investment in manufacturing equipment. And the payoff in increased office productivity is almost immediate.

The Paperless Office

Conventional office productivity increased a bare 4 percent during the entire decade of the 1970s.[12] At the same time, computers developed the ability to perform a great variety of office functions at a steadily decreasing cost per function. Taking advantage of these advances in electrotechnology, particularly for the information transactions estimated to consume the bulk of the workday for most office personnel, has become the obvious way to boost the efficiency of office operations.

By 1983, about five million computers or data terminals were installed in American offices. The first applications have been to computerize repetitious, routine tasks such as taking inventories or managing payrolls. And now, the electronic word processor is moving in to replace the conventional typewriter. So far, only about 10 percent of the typewriters in the nation's largest corporations have been replaced, but the trend is unmistakable. The word processors linked to the company's computers become part of one big electronic network that can carry communications almost instantly, not only within a single office but among different offices and organizations. Wall-sized two-way videoconferencing screens are expected to make travel to meetings unnecessary.

The "paperless" office of the future might, for example, microfilm all incoming information and store it for computer retrieval. Paper documents could then be discarded. Information generated within the office would never see paper at all. The person originating a memo or report could feed it into an electronic word processor, either by using the keyboard available on today's systems or by dictating into the voice-recognition attachment that is now under development. Then, instead of the communication being printed and mailed out, it could be transmitted directly to the recipient's word processing terminal via the growing telecommunications network that uses telephone lines to move the data electronically.

As Toffler points out, the new equipment can record a communication, correct it, duplicate it, send it, and file it automatically on the machine's tape or disk storage system "in what amounts virtually to a single process. Speed increases. Costs go down. And the five steps are compressed into one."[13]

The development of the new office technology naturally raises some questions about who will be doing what in the future. Will executives actually learn to type so they can key some of their communications directly into the network and be able to tap information from that network, without having to rely on an intermediary? Will that traditional intermediary, the secretary, then become a technically skilled administrator of electronic systems? These and other questions attend the prospect of increasingly automated work procedures in both office and factory. What will happen to all the people who perform repetitious manual tasks when "smart" machines have taken over the work?

The development of new office technology naturally raises some questions about who will be doing what in the future.

Indications on this point are equivocal. When automation was first introduced on a limited scale several decades ago, there was fear of massive unemployment. But employment in the high-technology nations actually expanded. In the United States and in Japan, investment in new technology during the 1960s and early 1970s correlated with growth in employment. Great Britain, which had the lowest investment in new machinery among economically advanced nations during that period, showed the greatest loss in jobs.[14]

New technology may eventually create as many jobs as it destroys. It can, in fact, give birth to whole new industries. The computer industry is a case in point. Millions of people are now employed manufacturing, selling, servicing, and programming the machines that did not even exist outside the research laboratory a few short decades ago. As our growing level of technology supports ever higher living standards, the demand for previously unavailable goods and services likely will create more such jobs in the future.

The snag for today's displaced workers is that qualifying for these jobs will often require skills that they do not have. The consequent need for retraining is probably going to be a fact of life for the neoindustrial workforce.

As technology expands to offer new work options, many people will have to accept the necessity for career changes to escape the decline of certain types of employment. Probably hardest hit will be production workers in traditional manufacturing fields. In Ohio's now depressed Mahoning Valley, long a steel center, the cost squeeze on combustion steel-making has idled some 50,000 workers. And in California, the closing of at least 400 automobile, steel, and other heavy industrial plants since 1980 has forced another 73,000 workers out of their jobs.

The trend toward fewer jobs in the smokestack industries is nationwide. Because these industries need to automate to survive in the face of foreign competition, many of these jobs will never return, even in an economic upswing. The main hope for displaced workers will be retraining, either to upgrade their skills for the increasingly computerized new jobs in their own industries or to take advantage of emerging opportunities in other fields.

Factories will not look, sound, smell, or feel like traditional factories. . . .

The Electronic Cottage

An attractive and increasingly viable option for many people is the prospect of working at home. Parents who need to care for small children during working hours, physically disabled people, and many other people who simply prefer not to commute to an office every day are finding that they can still work through computer terminals located in their homes. Many are already receiving regular paychecks from their companies for performing tasks such as bookkeeping or computer programming in these electronic extensions of the company office. Banks and insurance companies, as information-processing enterprises, are some of the first to experiment with this new workstyle.

Toffler refers to this phenomenon as the "electronic cottage"—"a return to cottage industry on a new, higher, electronic basis."[15] And he believes that this trend need not be limited to office work. The parallel shift from industrial to neoindustrial technologies in manufacturing will also reduce the number of production workers who have to manipulate physical goods. "This means," says Toffler, "that even in the manufacturing sector an increasing amount of work is being done that—given the right configuration of telecommunications and other equipment—could be accomplished anywhere, including one's own living room."[16]

He cites the case of an electronics manufacturing firm in which fully half the employees now handle information rather than physical components. Managers estimate that 25 percent of their employees could work at home today with existing technology, and that in a few more years virtually all the manufacturing firm's knowledge workers, or about 50 percent of the regular payroll, could make their contributions to the manufacture of electronic switching gear directly from their homes. Since knowledge workers in all fields are a growing segment of the work force, the possibility for both business and industrial employees to work at home seems increasingly realistic.

The workplace, then, is expected to be revolutionized by neoindustrial technology. Factories will not look, sound, smell, or feel like traditional factories as the new electrotechnologies gradually replace the throbbing steam boilers and noisy, heavy machinery of the past. In the office, the sound of clattering typewriters will give way to the quiet hum of electronic word processing equipment. And more and more homes will have computer terminals where the inhabitants can not only play games or analyze their budgets, but also perform work to earn a living.

So a shifting resource base—marked this time by the depletion of oil and gas fuels—has spurred the development of new technology in the United States and other advanced nations, just as wood depletion did in eighteenth-century England. And again, these changes in the methods of production are beginning to transform society as a whole. To provide some guidelines for assessing these changes as we head toward the year 2000, let us compare some features of traditional industrial society with those of the neoindustrial society now taking shape.

A New Society Emerges

Centralization of production has been a major feature of industrial life. Present indications are that this will change in coming decades. Production in the neoindustrial age is likely to be far more dispersed than would have been considered efficient or even possible using traditional technology.

This trend is already evident in the steel industry, where electricity-based minimills located at various points around the country are gradually taking over much of the production load formerly concentrated in the combustion-fired facilities of the now depressed Steel Belt states: Pennsylvania, Ohio, Indiana, and Illinois. Conventional steel manufacturing operations need to be concentrated close to sources of coal for coke production and sources of high-grade iron ore because both the fuel and the raw ore are expensive to transport. Minimills, in contrast, can be sited almost anywhere. Their fuel is electricity, which can be delivered instantly and cheaply to virtually any location; and their major material input is steel scrap, with the bulky and heavy waste materials present in the iron ore already removed. The high-temperature electrotechnology that allows minimills to utilize steel scrap thus allows them to lower the cost of transporting materials for production.

The decentralizing trend evident in the steel industry is becoming common in many other industries as well, and particularly in those that use computer networks to link their far-flung operations. "In an industrial society," comments social forecaster John Naisbitt, "when your company looks for a place to locate, you have to look for the infrastructure—water, transportation, and so forth." Combustion-based operations typically have required ample water supplies for steam generation and cooling purposes, a requirement that is reduced or eliminated in electricity-based operations. "With the new kind of companies we're building today," he says, "you don't need the infrastructure: You can put your facility anyplace. You look instead for the ambiance, for the quality of life."[17] Naisbitt states that 90 percent of the growth in the United States is occurring for this reason in the Southwestern states and Florida. On a smaller scale, he projects, the Boston area will undergo an economic revival because its strong cultural appeal draws high-technology enterprises that can locate wherever they choose.

Decentralization of production facilities within the United States is a trend upon which many forecasters agree. But when the prospect of world decentralization in manufacturing arises, opinions divide. Naisbitt is among the analysts who foresee the United States economy becoming more exclusively a provider of information and services, leaving much of the production of industrial goods to less mature economies.

Naisbitt feels that the nation's so-called smokestack industries are on their way out. "Without question," he says, "we are in the process of transitioning out of automobiles—and steel and appliances and textiles and . . . all of those industrial tasks that we used to do. As Third World countries take up those tasks, we let them go and move on to new tasks. It's occurring globally. All the developed countries are deindustrializing. . . ."[18]

Toffler, in contrast, sees the worldwide decentralization of manufacturing in less absolute terms. While it is true, he says, that fewer and fewer Americans will be employed in manufacturing and that more and more routine manufacturing will be handled by Third World nations, "for strategic as well as economic reasons, the rich nations cannot afford to surrender manufacturing altogether. . . . They will not become pure examples of 'service societies' or 'information economies.'"

"The image of the rich world living off nonmaterial production while the rest of the world engages in the output of material goods is," he says, "highly oversimplified. Instead, we will find the rich nations continuing to manufacture key goods—but needing fewer workers to do so. For we are transforming the very way goods are made."[19]

Rather than deindustrializing, the advanced nations appear to be reindustrializing. They are adopting new production technologies that will allow their basic industries to survive, but in altered form. America's smokestack industries likely will continue to turn out automobiles, steel, textiles, and all the rest, but the "smokestack" label no longer will apply because of the shift in production methods. As electricity-based neoindustrial technologies replace traditional combustion-based methods, even heavy industry no longer will generate the smoke that has for so many years symbolized economic growth and prosperity.

The decentralizing trend evident in the steel industry is becoming common in many other industries as well. . . .

"Transportation and communication technology has cut the cords that bound big corporations to the traditional headquarters cities". . . .

The decentralization of industry is expected to accelerate the urban population exodus. Cities continue to grow in the parts of the world still industrializing, but in advanced nations—those on the threshold of the neoindustrial age—the population flow is being reversed. In Japan and in most European nations as well as in the United States, major cities are showing population declines while small and middle-sized cities are growing. "Transportation and communication technology has cut the cords that bound big corporations to the traditional headquarters cities," reports Fortune magazine.[20] Many people probably will welcome the opportunity to relocate to smaller communities that offer a more comfortable, relaxed way of life if they can do so without sacrificing their well-paid jobs in major industries. As more and more industries decentralize their operations, more and more people will have a chance to do just that.

Working at home also can allow people to relocate to smaller communities without losing their jobs, whether the company moves or not. Toffler calls those who link the computer terminals in their electronic cottages to a distant workplace "telecommuters." As he points out, it takes less energy to move information than to move people.

Telecommuting could alleviate the freeway snarls and accidents that occur as commuters crowd into and out of the cities every day. What's more, it could save enormous amounts of gasoline. Toffler estimates that if even 12 to 14 percent of the commuters in 1975 during the severe gasoline crunch had stayed home and telecommuted instead, it would have saved 75 million barrels of gasoline, slashing the bill for oil imports.

The costs of physical commuting are borne ostensibly by the individual worker. But they are actually passed through to the employer in the form of higher wage requirements, and then to the consumer in the form of higher prices. The public also bears the burden of financing the city's roadways, mass transit systems, and municipal parking facilities. So the costs of commuting really are borne by society as a whole.

The trend toward smaller cities is consistent with an overall trend in neoindustrial culture toward smaller, more individualized ways of doing things. E. F. Schumacher, known for his "small is beautiful" concept, was not, as is often supposed, a foe of new technology. He was an ardent critic of industrial society and its emphasis on bigness, "but the cure," he stated, "is not found . . . by going back. . . ."[21]

"We have all been brainwashed," according to Schumacher, "by the experience of the nineteenth century, when, probably, the technological immaturity was such that it was true to say, 'The bigger the better': only on a large scale can you get the economics of scale. But that was a very immature technology. Now that is no longer true. Today we have enough technological and scientific knowledge to make things small again."[22]

And that, in the view of many futurists, is precisely what we are beginning to do. Neoindustrial production methods, in contrast to the large standardized production runs of the past, are able to create individualized items economically in relatively small batches. New technologies are allowing us to move beyond the emphasis on standardization and economies of scale, which in many cases no longer apply.

Automobiles and T-shirts are two types of manufactured items for which the trend toward customization is already clear. Even though the basic vehicle or shirt is mass-produced, the customer can order a variety of design features that are economical to add in much smaller runs. A more experimental variation on the same theme is the idea of giving pay-TV viewers an opportunity to choose the ending they prefer for a television drama: do the protagonists in a stormy romance reunite and work out their problems, or do they separate and find fulfillment in leading more independent lives? The viewers at each set can choose their own ending.

Each of these examples is a case of partial customization, and so an intermediate step toward total customization—the actual manufacture of one-of-a-kind products. Toffler cites the possibilities with a computer-controlled laser now available to the clothing industry. Rather than cutting the components for 100 suits at a time, it cuts one at a time in a way that is actually faster and cheaper than mass production. "The laser machines can be programmed to fill an order for one garment economically," according to the president of a large garment manufacturing firm.[23] One could simply key one's measurements into a home computer or have them taken by video scan and receive a reasonably priced suit tailored to order.

The ability to do things economically on a small scale has other implications as well. Besides allowing movement away from standardized products and procedures, it allows far greater access to the production system for far greater numbers of people. Small-scale neoindustrial production does not require the huge concentrations of capital that have characterized traditional production methods.

"An industrial society," Naisbitt observes, "is capital intensive. Lots of people know how to build a steel mill, but it's very hard to get that much money. In an information society, the strategic resource is your brains . . . so access to the economic system is much easier. That's why we're seeing a fantastic entrepreneurial revolution with new companies being formed."[24]

In the computer industry, for example, almost no capital is required to launch many types of enterprises. Small companies, many of them family-owned and based in the home, have sprouted throughout the industry. "A lot of companies go directly from the kitchen table to huge successes," according to an executive with a high-technology market research firm.[25]

Furthermore, little formal education is required. The new computer entrepreneurs range from Ph.D.s to teen-age whiz kids who plunge directly into high-technology ventures without benefit of a college degree. Opportunities abound for state-of-the-art assemblers, programmers, subcontractors, and systems producers to start businesses from their own electronic cottages. And now that the popular IBM personal computer can be equipped with its own robot arm, even home manufacturing operations are entirely possible without large capital investment. The emerging neoindustrial economy offers increased opportunities to people short on capital and even short on credentials, but long on good ideas.

The emerging neoindustrial economy offers increased opportunities to people short on capital . . . but long on good ideas.

Finally, there is considerable hope that the advent of new production methods—those that do not burn fossil fuels—will relieve society of the painful tradeoff that has existed between economic growth and environmental preservation. Few now dispute that the extraction and burning of fossil fuels to support traditional industrial production have produced some adverse environmental effects. But few have been willing, at least until recently, to sacrifice production to avoid these effects. Now such a difficult choice may no longer be necessary.

Coal burning, and to a lesser extent the burning of oil and gas, will still be required to produce the electricity that powers many of the new processes. But concentrating heavy fuel-burning activities at power plants rather than scattering them among millions of factories will simplify the task of controlling impacts on the nation's air quality. In addition, utility research is now providing methods that allow much cleaner use of fossil fuels, especially coal. And renewable power resources are being developed that eventually may replace fossil fuels altogether. The combustion of fossil fuels for industrial production, even for tightly controlled production of electric power, may become obsolete as the United States and other advanced nations move forward into the neoindustrial age.

In summary, neoindustrial society is expected to be very different from industrial society in a number of important ways. Its production methods will become decentralized as companies diversify geographically and more people work at home. Its large cities will shrink as workers, no longer tied to urban jobs, seek a more relaxed pace of life in smaller communities. Standardized mass production will be replaced by more customized goods turned out in smaller runs. Lower capital requirements in many neoindustrial fields will provide fresh opportunities for those who want to start their own businesses. And the clean, quiet electrotechnologies will support economic growth without threat to the environment.

The Neoindustrial Synthesis

Scanning all the very great changes neoindustrialization is expected to bring to society, one is reminded of Charles Berg's concept of innovation.[26] Innovation, in his view, is a way of doing things that eliminates or reduces the irreducible costs of former methods. Applying this concept on a societal level may illuminate the true promise of the changes now beginning to occur.

Technological innovation and social innovation need not be incompatible.

The costs of industrial life are well known. Work in a traditional factory has often jeopardized the body and deadened the mind. The many cultural and educational advantages of life in large cities have been offset by overcrowding, loss of community, and fear of crime. Standardization of work products and procedures has lead to what many people consider a dreary standardization of life itself. The capital-intensive nature of industrial production has excluded many would-be entrepreneurs from the economic system. And it has grown increasingly difficult for anyone to ignore the presence of environmental pollution.

But the human and environmental costs of industrial life cannot be erased by going back—by attempting to retreat to the preindustrial past. Clearly, as the vastly improved statistics on income, health, and life span show, industrial life has been in many ways a great improvement over what went before. The challenge now is to preserve and extend those gains, while reducing or eliminating the irreducible costs that have attended them.

What if it were possible to continue the quest for economic growth in a manner consistent with the quest for satisfying work, less stressful lifestyles, and a wholesome environment? What if the decades-long conflict between the demands of the marketplace and the pressure of these emergent values could be largely resolved?

Neoindustrialization offers hope of just such a resolution. Technological innovation and social innovation need not be incompatible. In fact, history has shown that they go together. A marriage of the new technologies with the new emphasis on human and environmental values may allow us to reduce the irreducible costs associated with an industrial economy, without sacrificing the very high level of material prosperity an advanced economy can provide.

Notes

1. Alvin Toffler, *The Third Wave* (New York: Bantam Books, 1981), p. 9. "The technetronic age" comes from Zbigniew Brzezinski, "the postindustrial society" from sociologist Daniel Bell, and "the third wave" is Toffler's own term for the neoindustrial future. The first two waves, in Toffler's view, were the development of agriculture and the Industrial Revolution.
2. Juanita M. Kreps and Joseph J. Spengler, "The Leisure Component of Economic Growth," in Howard R. Bowen and Garth L. Mangum, eds., *Automation and Economic Progress* (Englewood Cliffs, New Jersey: Prentice-Hall, 1966), p. 128–129.
3. Peter F. Drucker, *Technology, Management, and Society* (New York: Harper and Row, 1970), p. 81.
4. See Toffler, pp. 179–181.
5. Daniel Goleman, "The Electronic Rorschach," *Psychology Today*, February 1983, pp. 40–41.
6. "IBM Is Ready to Ship Its 7565 Robot System. . . ," *The Wall Street Journal*, January 25, 1983, p. 12.
7. American Association of Engineering Studies, position paper on productivity and innovation, as reviewed by Lucien E. Smartt, *Public Utilities Fortnightly*, October 14, 1982, p. 8.
8. See Smartt, p. 8.
9. "Nipponese Know-How," *Science News*, November 6, 1982, p. 299.
10. Ira Magaziner, as quoted in "Nipponese Know-How," p. 297.
11. Lauro Landro, "GE Promotes Factory Automation. . . ." *The Wall Street Journal*, October 21, 1982, p. 33.
12. See Toffler, p. 187.
13. See Toffler, p. 189.
14. See Toffler, p. 192.
15. See Toffler, p. 194.
16. See Toffler, p. 196.
17. John Naisbitt, an interview, "Restructuring of America," *U.S. News and World Report*, January 3, 1983, pp. 49.
18. See Naisbitt, p. 49.
19. See Toffler, p. 181.
20. See Toffler, pp. 298–299.
21. E. F. Schumacher, *Good Work* (New York: Harper and Row, 1979), p. 55.
22. See Schumacher, p. 21.
23. See Toffler, p. 184.
24. See Naisbitt, p. 49.
25. Dean Rotbart, "Husband-and-Wife High-Tech Businesses. . . ," *The Wall Street Journal*, September 17, 1982, p. 27.
26. Berg's concept of innovation is discussed in the second article of this series ((Mary H. Wayne, "Neoindustrialization: The New Technologies," *Electric Perspectives*, Winter 1982, pp. 29–41).

Forecasting Short-Term Fuel Prices: A View from the Trenches

By David J. DeAngelo

As regulators begin to scrutinize utilities' forecasting procedures more closely, so too must the regulated

Fuels departments within the utility industry are at a significant juncture in regard to the evolution of their forecasting and planning functions. Over the last several years, many utilities have switched from energy clauses based upon historical or actual costs to clauses based upon forecasted fuel costs. At the same time, regulatory interest in utilities' procurement and planning procedures has increased at both the federal and state level. Moreover, regulatory authorities' emphasis on the analysis and documentation that back up utilities' fuel price forecasts and fuel planning procedures probably will continue to grow.

As a result, utilities may find the mid-1980s to be an era marked by the development of numerous fuels management tools. Of course, some other functional areas within utilities already have been exposed to such analytical development—capacity planning departments adapted models to their use in the mid- and late 1960s, and load and sales analysis groups developed advanced forecasting models in the early 1970s. Soon, the fuels departments of the industry will be at bat.

Before this trend toward more analysis proceeds further, however, we fuels planners should pause and attempt to define our problems. Too frequently, action is taken without consideration of this necessary first step, and, as a result, resources are wasted.

In this article, I will discuss only one area of future development: short-term price forecasting. (By "short-term forecast" I mean a monthly or quarterly forecast with a one to two year time frame.) After proposing definitions of the problems involved in forecasting short-term fuel prices, I will outline some of the organizational, technical, and procedural practices that we at Pennsylvania Power & Light have developed to remedy or minimize the problems. I will also point out some of the pitfalls to be avoided in developing and applying fuels management tools and procedures.

Defining the Problems

Very simply, a forecast can be described in terms of stages—the forecaster starts with data, transforms it into information, and then uses the information to generate a forecast. The problems one confronts in this process fall into four general areas. The first can be termed the *availability of data*. As a general rule, the larger the market, the greater the number of parties that desire information about it, and, consequently, the greater the availability of published data concerning it. If the market is large, trade associations and government agencies frequently publish timely information about its operating rates, inventories, production levels, etc. Oil markets fit into this category, and the American Petroleum Institute and the Department of Energy are examples of organizations that provide considerable amounts of data about them. However, where markets are more narrowly defined geographically, the forecaster may have difficulty in obtaining data on explanatory variables. He may, in fact, have to rely solely on internal company records. In such instances, there are obvious limitations to modeling "the market." All too frequently pieces are missing from the mosaic of available data. Consequently, a forecaster must develop a talent for drawing inferences. Courage helps as well.

This lack of hard data poses a second problem—how to squeeze the most information out of available data. Since the forecaster is striving to *maximize the information* with which he can forecast, he must gather as much relevant data—ranging from hard quantifiable facts to subjective stated opinions—as pos-

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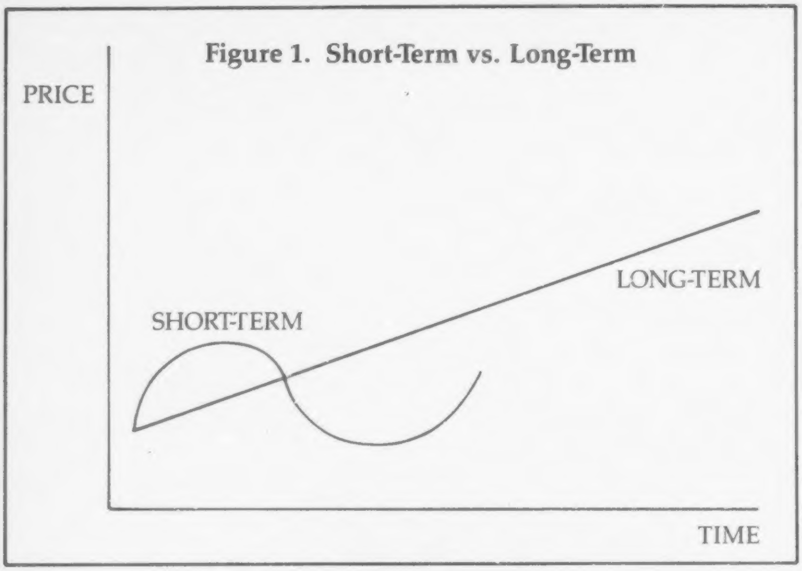
Figure 1. Short-Term vs. Long-Term



sible within given time limitations. Then he must analyze the data, filtering out the noise and twisting, bending, and shaping the data by whatever means are at his disposal to glean every nuance of information from them. While this effort to maximize information is not sufficient to ensure a good forecast, it is the necessary starting point.

The very nature of short-term prices—as opposed to long-term prices—presents a third area of problems. If long-term prices can be thought of as equilibrium prices, short-term prices can be characterized as *disequilibrium* or cyclical prices. For each, different forces prevail. Long-term prices have been linked traditionally by economists with supply. Hence, productivity, cost of production, and rate of return are viewed as dominant forces acting on long-term prices given the various levels of demand. In the short-term, however, markets are moving from one period of excess supply or demand to another. As shown in Figure 1, short-term prices oscillate around the long-term trendline. Between the turning points, or peaks and troughs, there is the process of adjustment. Over a one-to-two year period, we can expect at least one of these turning points. Specifically, it is the task of the price forecaster to both anticipate the occurrence of turning points and to predict the magnitude and duration of the corrections that follow them. *Obviously, long-term equilibrium models are ill-equipped to do so.*

Likewise, the forecaster of short-term prices must avoid falling into the trap of merely extending the particular trajectory of the current market. Easy to say; difficult to do. As noted in the May 1982 *OPEC Bulletin*, "The tendency has been for forecasters [and managers, I would add] to be conditioned by the psychology of market trends at the time of their calculations."[1] Let there be no mistake, the forecaster has to be resolute to resist the sometimes overwhelming allure of simple price extrapolation.

At the heart of the fluctuation in short-term prices are the fluctuating perceptions of the participants in energy markets. Although the final effect of these perceptions translates into shifts of supply or demand, the starting point tends to be changes in inventories (stocks)—the buffer by which businesses adapt to changing prospects.[2] History is replete with situations in which fuel producers or consumers have decided that their inventories are too high or, conversely, too low. De-stocking or stock buildup have ensued, along with commensurate changes to price.

Speculators and traders in energy markets magnify or exacerbate these underlying economic forces. Operating at the margin and in the spot market they "daisy chain" on the upside and dump on the down side. Needless to say, it is very helpful for a forecaster to understand "market psychology."

International political forces also act to keep short-term prices in disequilibrium. The most glaring examples are the geopolitical shocks that have come from the Middle East. Moreover, the area remains a cauldron that could boil over at any time.[3] Until very recently, we could have said that politics primarily affected oil; not so today. With Poland's internal strife and subsequent curtailment of coal production, the United States coal export market flourished in 1981 and early 1982. This boom had a clear impact on domestic steam coal prices. For natural gas, we can cite the recent Soviet Siberian pipeline issue. In short, forecasting fuel prices has taken on a geopolitical dimension that lies outside the normal scope of expertise found in most domestic utilities.

In addition to the problems created

by the availability or unavailability of data, the need to maximize information, and the fluctuating nature of short-term fuel prices, the area of *communication* also presents problems for the forecaster.[4] Regardless of the complexities of the technique used in developing a forecast, that forecast will have to be communicated in a convincing manner to upper management. Although analysts in fuels departments may be very comfortable speaking in a "modeler's mode" with their peers from other utilities or consulting firms, they must switch to a "management mode" when conversing with those above them on the corporate ladder. Clearly, it is detrimental to a forecaster's acceptance and effectiveness to be regarded as one who lives in an ivory tower.

Solving the Problems

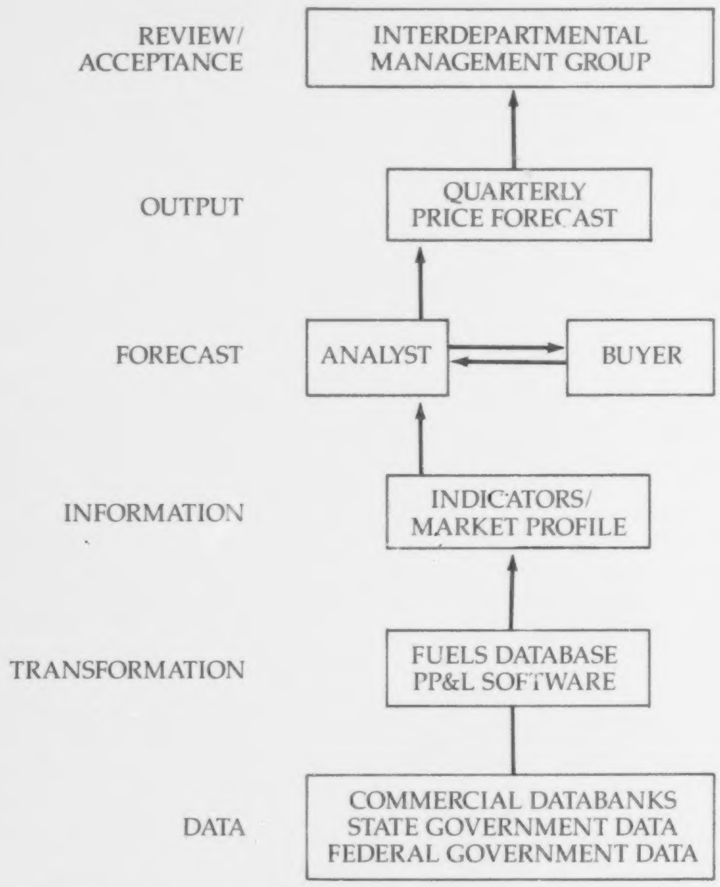
Having analyzed the problems we confront when forecasting short-term fuel prices, our next step is to identify and analyze the resources that can be applied to the task of solving them. Here I will limit myself to a discussion of the human resources available: the buyer working alone, the analyst working alone, or the two working together. Discussions with representatives from a number of utilities have indicated that many utilities rely primarily on the buyer for their short-term fuel price forecasts.[5] However, given the problems involved and the regulatory commissions' growing emphasis on analysis and documentation, utilities will have to shore-up the resources being applied to the task.

There is no doubt that the buyer's primary strength in making the fuel price forecast is his "feel" for the market as an actual participant in it. However, the time required to prepare a thorough forecast, complete with a detailed analysis of data trends and indicators, limits the buyer's ability to fulfill his primary operational responsibility. Further, to the extent that many lack the appropriate skills, quantitative analysis often is beyond a buyer's capability. Lastly, a buyer's concentration on a particular fuel market can distort his perspective of a utility's total energy picture, both in regard to different time horizons and different markets.

The boom in the U.S. coal export market during 1981 and 1982 had a strong impact on domestic steam coal prices.

In contrast, a trained and experienced analyst brings to the forecasting effort a bag of tools that can range from time series analysis to the more complex model-building techniques of econometrics, linear programming, and simulation. Also, because they are his primary responsibility, the forecasting and planning tasks will receive the analyst's full attention.[6] These techniques, of course, imply an emphasis on the use of hard data. Regarding supplementary data and information frequently used in the forecast process, buyers and analysts have alternative sources because of the different spheres in which they operate. Buyers can obtain data from their peers and fuel vendors. Analysts, on the other

Figure 2. Short-Term Forecast Procedures



hand, can tap information from a multitude of energy planners and economists who work in academia, consulting firms, the government, and other energy companies.

Of course, the analyst is not without weaknesses. Besides not having the day-to-day contact with the energy markets that the buyer has, there is no assurance that the analyst will communicate the forecast effectively. In fact, there is reason to expect analysts who have spent significant amounts of time in graduate school to have problems in this area.[7]

An attractive alternative to using either the buyer or analyst alone to develop the fuel price forecast is to allow the two to work together. A joint effort, one with which we have had success at Pennsylvania Power & Light Company, combines the technical capabilities of the analyst with the market savvy of the buyer. Under this approach, the analyst functions much as the intelligence staff in a military operation. It is his job to collect all the relevant data, correlate it, look for the short-term trends, and then work with the buyer and incorporate into the analysis his insights. In this way, we maximize the use of hard data (the most acceptable basis for documentation) and the amount of information we obtain from a given set of data.

A joint effort also promotes greater objectivity than either of the individual efforts does. Because it is based in many instances upon judgments, a forecast should be subjected in every way possible to objective scrutiny. In a joint effort, each party can act as a foil or devil's advocate to the other. The buyer's real world contact can temper the analyst's pursuit of statistical precision, and the analyst's dispassionate perspective can offset the buyer's susceptibility to the emotion of a particular cycle in market price.

Lastly, a synergistic bonus is realized if the analyst and buyer prove compatible. Whereas, fuel price forecasts tend to be viewed strictly as products for input by *other groups* to budgets, the joint-effort forecast process also can provide market research feedback (in both an operational and a planning sense) to the *buyer* himself.

The procedures that we follow at Pennsylvania Power & Light Company to develop our short-term fuel price forecasts are shown in Figure 2. These procedures have evolved over the last several years to fit our particular organizational structure.

Each month several data series are collected—some from commercial data banks, some from the government, and others from within the corporation. After they are entered into a Fuels Department energy databank stored in our corporate computer, they are translated with our software into a series of indicators.

The indicators have been selected because of their informational value. They represent forces that lead price movements, particularly turning points. For residual oil we have developed more than fourteen indicators that can be placed into three groups—crude/residual relationships, supply/demand/stock relationships, and intra/intermarket price relationships. For coal we have been monitoring production, productive capacity, and burn/stock ratios.

When the indicators are combined according to fuel type, they represent a market profile. The analyst brings the profiles to monthly meetings with the buyers where they serve as a basis for discussion of both the current market and the joint forecast.

Forecasts are issued quarterly. They are reviewed and approved by an interdepartmental management group representing each of the Company's major divisions: System Power and Engineering, Operations, Finance, and Human Resources. Once the group accepts the forecast, a *Fuel Price Forecast* newsletter is sent out to concerned parties. The newsletter not only keeps management apprised of events in the energy markets but also provides running documentation of the forecast.

In summary, the joint-effort forecast and the procedures that we follow to produce it help minimize the problems inherent in the task of forecasting short-term fuel prices—more data are available, more information is gleaned from them, fluctuations in disequilibrium prices are more accurately predicted, and the final communication of the forecast to upper management does not depend on the skills of a single individual. The end result is a forecast that is both documented and defendable, attributes that will grow increasingly valuable as regulatory commissions grow increasingly interested in utilities' fuels procurement and planning procedures.

The end result is a forecast that is both documented and defendable. . . .

Notes

1. *OPEC Bulletin*, May 1982, p. 6.
2. Inventories enter both the supply and demand sides of a utility's fuel market: Supply of Fuel equals Production minus Change in Inventories; and Demand for Fuel equals Burn plus Change in Inventories.
3. Political, religious, and national differences stoking the fire are exemplified by the Syrian/Iraqi Baathist rivalry, the Shiite/Sunni Muslim differences, and the continuing Arab/Israeli conflicts.
4. Thomas H. Naylor addressed this issue in "The Politics of Corporate Economics," *Business Economics*, March 1981.
5. In July 1981, PP&L hosted an initial utility price forecasting conference. A subsequent meeting in May 1982 was hosted by Commonwealth Electric. The "discussions" that I allude to were held at those meetings.
6. Although an analyst can work on both planning and forecasting, they are different functions. A forecast is one input to a plan.
7. Naylor, *Business Economics*, March 1981.

INDUSTRY
COMMITTEE

Edwin Vennard: Telling the Public

Emphasizing the value of marketing, public opinion research, and education, a former utility executive recalls how the industry confronted its problems in the 1930s and 1940s

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I grew up in New Orleans, Louisiana. My mother and father lived there for years. Early on, my dad explained to me that he could not send all four of his sons to college and that if I had to go, I had to get a scholarship. So I began high school, knowing I had to get a scholarship—so I did. They gave two each year from the high school, to Tulane. I took engineering, because my brother had and, by the way, I became student body president my senior year.

At that time General Electric would hire about 500 engineering graduates each year and put them through an advanced course in Schenectady. They called it "the test course." Three of us from Tulane were picked. GE expected half to stay with the company and the other half to leave and go elsewhere. I took the course, still not knowing whether I wanted to be in engineering or what.

I finished that in 1925, and then took a job in Lake Charles, Louisiana. I remember that every week there would be a bulletin board offering jobs anywhere in the country, because companies all over went to GE to get these people who went through the test course. Each week we had eight or ten jobs to choose from. The reason I took the particular job I did was that during my sophomore year at Tulane I met a young lady from Lake Charles. I had to go see her, but I had no money. Well how do you get to Lake Charles without any money? I formed a glee club. I organized it and became manager. Then I organized a tour for those 40 singers to Baton Rouge, Shreveport, Alexandria, Lake Charles, and back. When we got to Lake Charles, the girl was at a houseparty someplace else. I was glad the revenues of the tour covered its expense because the whole school soon learned of the plan. I said okay, that's gone forever. But when a job opened up in Lake Charles, I said, well, I'll go to Lake Charles and work there. I was a power sales engineer with Gulf States Utilities Company.

When I got there, I found the girl had gone to Hollywood. She was in movies about five years. So I said, "Bye-bye,

Edwin Vennard has been characterized by one associate as someone "who knows more about the electric power business than any other man in the country."

For some 60 years, Vennard has served as an industry leader. He was employed by Gulf States Utilities in 1925, then in 1926 he joined Southwestern Gas & Electric Co. (now Southwestern Electric Power Co.), becoming general commercial manager in 1928. In 1933 he joined the parent organization, Middle West Utilities Co., in Chicago and helped guide it through a series of crises including the Depression, its bankruptcy, the drive for government utility ownership, and the diversification required by the 1935 Public Utilities Holding Company Act. Simultaneously, he spearheaded the first national utility movement to monitor public opinion and expand public communication programs.

As Vennard worked to expand Middle West Service Co., which was owned by Middle West Utilities, he also helped expand the industry's national programs, leading to the establishment of the Electric Companies Advertising Program (ECAP), the Public Information Program (PIP), and the National Association of Electric Companies (NAEC). He joined Edison Electric Institute in 1956 as its managing director, a position he held for 13 years. (The title has since been changed to president.) When Vennard retired, he joined Commonwealth Management Consultants as its president and became vice president of its parent company, Commonwealth Services, Inc.

Vennard's contributions also include numerous books and pamphlets covering a wide range of topics ranging from the economics and management of the electric utility business and government ownership of power systems to the American economic system. He has written several books familiar to those in the industry including *The Electric Power Business, Government in the Power Business,* and *Management of the Electric Energy Business.*

Today Vennard, at 80, still is using his expertise to solve energy-related and economic problems facing the United States and other countries. He serves as an independent consultant specializing in energy and public utilities and also travels around the world for Overseas Advisory Associates, Inc., an organization formed by Walker Cisler, to provide foreign countries with energy management assistance. Recently he completed a comprehensive plan for electricity development in Taiwan through the year 2000.

This article is the third in a series focusing on former electric company executives. The text was taken verbatim from the transcript of a recent interview with Mr. Vennard.

little sister, that's the end of that one." Five years later we got to talking back and forth, and I went out there and we got married in 1929, in Hollywood. That took her out of pictures.

After I was at Lake Charles for about a year, a job opened up in Shreveport, so I moved there as a power sales engineer. Sure enough, the next year I became general commercial manager for the company. So there I was at 27 years of age in a high position, with a department of about 200 people, in charge of pricing, marketing, economics, customer relations, and things like that. The company was one of about 50 companies in the Middle West Utilities holding company system. The Middle West experts taught me and guided me. In those days about seven holding companies owned almost all the electric utilities. This one was in Chicago and had been formed by Sam Insull. He had been Edison's business manager, and helped to form utilities around the country and became head of the one in Chicago. Then he formed this company, Middle West, to operate about 50 utilities in 17 states. I was called in 1931, by the then-president of the company, to come be his assistant.

I don't know how he picked me out. How do you judge these things? I think he was at a meeting where I made a talk. The lesson is: learn to speak because you can't tell who is listening. The head of the company would never make a speech. He had me make them. So I said yes, even though my boss said I was crazy to go. But a few months later they called and said don't come: Insull's gone to Greece. The whole country was against utilities. They said we had caused the Depression. And Sam Insull, one of the greatest financiers, had everyone after him because people lost money in the stock of his companies. His lawyers advised him to go to Greece quick, so he took a freighter. It was very bad. He was indicted on 17 counts of fraud. He had put all of his personal fortune back into Middle West Utilities, trying to save it from bankruptcy, but it went under. Then a man named Matthews was brought in. He was chairman of the Wisconsin Commission. Middle West fired all the top officers. Because the company was in bankruptcy, the court had appointed a man named Dan Green as trustee. He hired Matthews, and Matthews called me to be his assistant. I said, "What's going on up there?" He said, "We're getting organized, come on up." I did.

When I walked into his office, he said, "I have news for you. I'm leaving tomorrow for Washington to be on one of Roosevelt's commissions." I said, "What am I supposed to do? I have left my job in Shreveport." He said, "We'll go see the trustee." When we met with Dan Green, he said, "Can you run it?" I said, "I'm 31 years old." "I didn't ask you that. Can you run it?" I said, "Okay, yes."

So I began rather early in a fairly high position. I then was made vice president, and there I was, a principal department head of a holding company, in bankruptcy, that owned 50 utilities in 17 states. Our earnings were very, very poor. The average of all the companies was 3 percent return after setting aside 1 percent for amortization. (This was before depreciation accounting.)

People today can't imagine the Depression, with 25 percent unemployed, and people being let out all over. Our earnings were low and we had 100 percent excess capacity. That was because Hoover had called the leaders of industry down to Washington and said please keep expanding, to hold back the Depression. Insull had come back and said full speed ahead. We kept on building plant with everything going down in earnings. That's what caused the bankruptcy. He was trying to help save the economy. Parenthetically, when he came back from Greece, he stood trial on all counts, and was guilty of none. We found nothing in the Middle West record to show any guilt. He was a great builder.

. . . Hoover had called the leaders of industry down to Washington and said please keep expanding, to hold back the Depression.

We began a big drive to bring the companies out of their low returns. We instituted a 7 + 3 program—build to 7 percent return after 3 percent depreciation. We did it by tremendous expense reductions. People today don't know what you must go through when you really have to cut expenses to economize. On top of that, we *sold* the energy, we marketed, we promoted—actively promoted. I believe this promotion during those years is what really caused America's movement out of the Depression. We did it by promoting everything. You see, the average income per capita was quite low. The annual residential bill was about $30. Now it's about $400 or $500. Then it was less than $3 a month. Of course, all that most people had then was a drop cord, a light. We had almost no appliances. We had no refrigerators. We had no ranges. We had no water heaters. We had no sweepers. We began developing those things.

I had begun in Shreveport. People didn't have any sweepers, never heard of a vacuum cleaner. I hired men to go around and sweep people's homes. I said, "You sweep five homes per day, and I'll pay you to do that." One in five would buy.

Then somebody thought up a washing machine. I hired men to take one, put it in the car, and go wash clothes. Just wash five per day. They'd go there and wash the clothes. One in five would buy.

We had a home service department. As soon as a customer bought a washer, one of our young ladies would go there and recommend they have a party for all the neighbors. She would bring the neighbors in to show them how these things worked.

Somebody invented the refrigerator --we were all using ice then. So we began selling refrigerators. That's what I mean by promoting. When you promote things and people buy them, one housewife will want a refrigerator because Mrs. Jones has one next door. Well, pappa says, "Honey, I can't afford that. We haven't got the money." Her answer is, "Well, by God, get the money. Go work harder." So he goes out and works harder to get the money to buy the refrigerator. And you make refrigerators, and you make ranges, and you make water heaters. We saved the American economy by building it, by promoting it, by marketing.

Of course, we had conservation, too. There's nothing new about that. We had to conserve to cut expenses—that's conservation—to exist. As I say in my book on Taiwan, the utilities are the best example of conservation. I don't know why we don't tell that to the public. We cut the pounds of coal equivalent to make one kilowatt hour from eight in 1900 to seven-tenths today. We did it by improving efficiency—higher temperatures, higher pressures, more research.

At Middle West, Vennard (center) strove to improve companies' return by cutting expenses and promoting electricity use.

When we stopped using energy—down went the economy. Some utilities are glad to have no growth. They don't have to build power plants. They don't have to finance them. Okay. If I were a head of a power company today, I would put all my time and energy into convincing the public that we have to get the earnings to build power plants to get out of this Depression we're in. That's what's causing it. We've got to get back to the elementary ABCs in energy. It is electric energy that pulled us up in total production because most of the machinery of production is run by electricity. And we built that. But about ten years ago the regulatory bodies said, "Stop all marketing, stop all growth," and ordered people to stop marketing. Well, they stopped promoting. Then came what they call the recession. They said, "What happened?" Well, by God, you stopped growth.

You see, the job in Chicago was to help the companies build their earnings. At that time, utilities were in great disfavor. Many people had lost heavily in the stock market, and they blamed the utilities. All during the '20s they had been buying and buying and buying. They built the price way up, and then the market crashed. They lost all their savings, and they blamed utilities for that. They blamed Insull.

Roosevelt came in, and he was a leader against utilities. In fact, he be-

So I went back and told those people at Middle West, "I want to go to the public."

gan a campaign to nationalize the power businesses. If you have time, look at my book, *Government in the Power Business.* You don't need to read the whole book, but you skim through it. They say things are tough now, but I can't imagine it being tougher than having the whole government trying to put you out of business. All that force, going to give public money to build plants to put you out of business. And you in bankruptcy. Times are tough today, but they were much tougher then.

Let me tell you about bankruptcy. The bondholders take over the company. They go to the court, and the court takes over and appoints a trustee. He would say, now you just make the best deal you can for the bondholders. The trustee is supposed to do the best he can to pay off the bondholders because they're not getting their bond interest. They own the property.

One day I told the trustee, you're sending me to Washington to deal with those people down there and we're getting nowhere. I said, I've heard of a guy named Gallup. He became famous when he predicted that Roosevelt would beat Landon. He had a company that did political surveys, and he also formed Opinion Research Corporation with Claude Robinson as his partner. They were a survey agency for anything. I told the trustee, why don't we hire that firm, Gallup and Robinson, to survey the public to see if they want government ownership, and if so, why. It might tell us what to say. This never had been done.

You know what convinced me to go to the public? In 1931, I was at a meeting of the Association of Edison Illuminating Companies. That's the oldest association in the industry, formed by Thomas Edison. All the people were crying, crying, about government takeover. The chairman of the meeting said, "I see in the audience Owen D. Young." He was chairman of General Electric Company and the author of the Young plan to rehabilitate Germany after World War I. The chairman said, "Advise us on this terrible situation we're in." Young was very tall, very stately, and very solemn. He got up and said, "Why don't you tell your story to the public." He then sat down. So I went back and told those people at Middle West, "I want to go to the public." And that's what brought about a change.

We drafted a questionnaire. When we began, we had our eyes opened. We surveyed a complete cross-section of 17 states, and we found that 70 percent of the public said they were in favor of government ownership.

When we analyzed the "why" answers, we found great areas of ignorance. This was all new to us then. The first reason why they wanted government ownership was they thought they would get a lower price with government. Okay. The next question was: has the power company that serves you reduced your rate in the past 10 or 15 years? Eighty-five percent said "no" or "don't know." Fact: we had cut the price in half. We were being enlightened. With the survey agency and with an advertising firm we designed a sentence on that one specification. In fact, we developed 12 specifications, 12 areas of ignorance to correct, all having a bearing on the desire for government ownership. Number one was price. We wrote this sentence: *The average price of household electricity is about half of what it was 10 to 15 years ago.* Now, the best ad by anybody in the country will get about 10 percent readership. The reason people know that Ivory Soap floats is that it has been said to every person at least four times. We wanted to be sure everyone in the 17 states we served saw that sentence four times. Run it 10 times, you get it once; run it 40 times, you get everyone four times. We ran that thing 40 times in full page ads in 17 states. The thing was expensive, and we had 12 specifications. Don't forget, with bankruptcy you've got to save the property. You need to spend money to do that. After two years of this advertising, a resurvey indicated a drop from 70 to 30 percent in favor of government ownership.

During this two-year period, I got calls from people all over the industry: "What are you doing out there? Let me know the results." I was asked to organize a similar program on a national basis. Still, it took me about a year to find five men who would be an organizing committee to do it nationally. I guess I talked to 40 or 50 people, trying to get them to do it, but I got five. Grover Neff of Wisconsin Power and Light, Kinsey Robinson of Washington Water

Power, Tom Walker of Gulf States at Beaumont, and the president of Kansas City Power and Light Company. But I think what got the program going was when Horace Liversidge, the chairman of Philadelphia Electric Company, one of the big Eastern companies, came in. I had five good men and we said let's begin ourselves. Let's run the first ad. We put up the money. We made that first ad so innocuous. I can recall the ad now. It had a picture of a man with a gun, a soldier—Johnny, where'd you get your gun? We described industry making the gun. You can't get mad at that.

Well in Middle West, we had used one of the big advertising agencies, one of the biggest. We used the Chicago office to run our Middle West ads. We offered this big national account to the same agency. The head of it was as well known among businessmen then as Bill Simon, the former Treasury Secretary, is now. He called me from New York and said, "I want to come see you." He came to see me in Chicago. He said, "First, I want to thank you for offering us the account. Then I must tell you that we can't accept it." "Well," I said, "I'm surprised. Why is that?" He said, "You're trying something that's impossible. They'll stop you before you even get started, and we can't afford to be in that position. We have too much at stake." "If you think things are that bad," I said, "that's all the more reason for going ahead!" It just gives an idea of the fear of businessmen in those days.

Having run the first ad, I began canvassing. I had my little package of charts. I called every company and said, "I will come to see you if you'll give me two hours and have all your top department heads there. They'd set it up, and I would go give my story. Every two presentations brought one new member. We wound up with about 60 percent of the industry. Eventually, we were spending $3.5 million a year nationally, in national magazines and radio. We prepared mats for companies to use in local newspapers. Don't forget that this was not until 1940, 1942, and '43.

Our national surveys showed about the same results as the 17-state survey—70 percent favoring government ownership and about 12 areas of ignorance. Concerning the story on price, nationally, I was waiting to be able to re-survey to see what progress was being made. Before I could do it, the Mutual Life Insurance Company made a survey of its own. It listed a lot of commodities and services, and said please check the ones that give you the best bargains, hoping they would say insurance. They sent the results to me because they picked electricity as the best bargain. We hadn't changed the price, we had explained the bargain.

We hadn't changed the price, we had explained the bargain.

After about 10 years of the national program, we had reduced the 70 percent in favor of government ownership down to about 30. Since then the percentage has leveled off at about 20 percent.

We surveyed and came up with the terms "investor ownership" and "government ownership." Those were our terms. It took us years to get even ourselves to stop saying "private ownership" and say "investor ownership" instead. Some companies had a piggy bank on the table. If any guy said "private ownership," he put two bits in the pot.

But I'm getting ahead of myself. In the mid-1930s we were in bankruptcy. The holding company, Middle West Utilities Company, was in bankruptcy. The law said we must liquidate, but you can't do that overnight. It took us 10 years to liquidate.

Let me tell you what "liquidate" means. It means to stop being a company.

We owned about 50 properties. We had to divest ourselves of the stock of those companies, either by selling them or by giving the stock we owned to somebody. In some cases, we formed a company like Central and Southwest Corporation. At that time, Middle West owned the common stock of Central and Southwest. Middle West gave its Central & Southwest stock to the Middle West stockholders, and we no longer owned it. Gradually, we either sold the property or got rid of our common stock. It took about 10 years.

In the meantime, the trustee and the board that had been established had formed a service company. The corporation was the holding company and employed only a few people. It owned Middle West Service Company, which was made up of about 200 people. That's where I worked. Early on I said

For 13 years, Vennard served as managing director of Edison Electric Institute.

to the trustee, why don't you divest yourself of us, the service company. Make us independent of you. Let us be an independent consulting firm, and hire us, for a fee, to give you service. You're going out of business. We don't want to be tied to a dead cat or a dying cat. They said no, no, no. Go on about your business. When they were all done and had no more stock that they owned, the trustee then called me in. He said, "All right, we're out of business. Now go form a company, a consulting firm, out of all this staff. When you've formed your company, we will then give the new company everything we own of Middle West Service Company. Actually, all they owned in physical property was typewriters and desks. The value was in the good will of the clients and the Middle West people. So it was given to us. We formed a company of seven people, and we were given the stock. Half the net revenue went to all employees as a bonus. We called a meeting of all of the presidents of the operating companies that had been part of our holding company system. Most of these guys I was raised with, you understand. This is now 20 years later. I knew them personally, and we had gotten along well. They were good friends of ours. I said to these men, "Middle West is out of business. We've been asked to form a service company. We've got about 200 people here. If you want to, we'll liquidate and you can hire them. They're all good workers. You know them all well. You'd like to have them. But if you want to, we'll simply change this organization to a consulting firm. We don't own you anymore, but do you want to buy our service?"

They said, "How much are you going to charge?" I said, "The same thing you have been paying plus 10 percent profit." They all laughed and said, "Okay, that's fair enough." Every man said yes. "But," they said, "from now on you don't tell us, you sell us." That is, we went into the consulting business with everything underwritten. That was a nice position to be in. We were a going concern with a profit. We were fairly well known then around the industry, through my work with the advertising program, so we began taking on other clients. In fact, we doubled our clients in just a few years. We provided only management services, not engineering, design, or construction. The big money is in engineering. For the clients, we monitored the engineers and constructors that they employed.

We were close to merging with Commonwealth Services, which did the engineering work for the subsidiaries of Commonwealth and Southern Company—Wendell Wilkie's company. We were providing management services for a number of their clients. Then I came to the Institute and 13 years later, when I was ready to leave EEI, Commonwealth called me and asked that I become president of Commonwealth Management Company.

I have never practiced engineering as such. If I had to go back again to college, I'd take engineering because I think engineering gave the kind of education I needed for the work I have done.

I don't think I planned long-term. I've always been ambitious and I wanted to get to the top of wherever I was. I figured the best way to do that is to do the job I had to do, and do the best I can with the job at hand. But there were a couple of breaks. You can't escape a break.

I have a great belief in the axiom that a person's judgment on any subject is no better than his knowledge of that subject. Without the knowledge, he does not exercise good judgment. Every day somebody in a power company is making a judgment. When you get into a management position, almost every hour you're forming a judgment and making a decision. Management is a team effort, not just one person. I try to explain that in my latest book, *Management of the Electric Energy Business.* Anybody who has somebody working for him or her is part of management. The judgments that get made anywhere along the line are important, and they all depend on the knowledge. That is why education, at all levels, is so important.

Challenges of the Decade

In spite of declining interest rates, rising stock prices, and decreased inflation, the electric utility industry is faced with some significant challenges in the area of rate regulation, today and in coming years.

One important challenge the investor-owned electric utility industry continues to face is restoration of its financial health. Although the market for some electric utility common stocks has improved somewhat recently, several financial indicators provide clear evidence that there is still profound need for improvement in the financial condition of electric utilities. For example, actual earned return still lags behind average authorized return, which was approximately 15.9 percent for 1982. Moreover, based on cases for which data are available, average authorized return falls far short of the 17.75 percent average sought in applications filed during the second half of 1982.

Also, the non-cash component of net income available for common equity, commonly referred to as Allowance for Funds Used During Construction or AFUDC, has remained high, having increased from 12.9 percent in 1969 to an estimated 44.5 percent in 1982 (which is some improvement over the 44.8 percent in 1981). But this average does not begin to describe the startling variations in AFUDC among utilities. For some utilities, AFUDC exceeds 100 percent of earnings. Dividends paid on non-cash earnings must be financed by methods other than earnings.

Rate increases received in 1982 showed a downward trend from the record amount in 1981 (see Table 1). Investor-owned electric utilities received 308 increases totaling $7.57 billion, compared with 319 increases totaling $8.34 billion in 1981. These increases do not include fuel clause adjustments. As of December 31, 1982, there were 180 cases pending, for about $7.69 billion. At the same time last year, the figures were 186 cases for about $8.39 billion.

The decline in rate increases is not a good sign for an industry that plays a vital role in the nation's economy. Under current financial pressures, it takes up to 14 years to bring a base-load generating unit on-line, and, due to a decline in the growth rate of the economy as well as the implementation of con-

Adapted from a speech delivered by Dr. Douglas C. Bauer, Senior Vice President of the Economics and Finance Group of Edison Electric Institute, at the Ninth Annual Rate Symposium, which was held in February in Kansas City. Contributed by the Rate Regulation department of Edison Electric Institute.

Table 1. Investor-Owned Electric Utilities—Electric Rate Actions Five-Year Summary for Years 1978–1982

	1978		1979		1980		1981		1982	
	Number of Actions	Total $ Amt. ($000)	Number of Actions	Total $ Amt. ($000)	Number of Actions	Total $ Amt. ($000)	Number of Actions	Total $ Amt. ($000)	Number of Actions	Total $ Amt. ($000)
Filed During Year[1]										
Increases	154r	4,494,132	178r	5,741,235r	253r	10,867,711r	237r	11,902,261r	228r	11,848,211r
Decreases	1	104	3r	1,367r	3r	1,786r	3r	9,565	2	24,093
Pending at End of Year[2]										
Increases	165r	3,855,781r	163r	4,872,815r	219r	8,134,932r	186	8,387,635	180	7,689,520
Decreases	1	104	1	237	2	1,757	2	6,246	3	19,228
Approved During Year										
Increases	200	2,419,345	195r	2,880,870r	247r	5,935,490r	319r	8,340,815r	308r	7,569,094r
Decreases	5	26,423	14	88,392	11	81,235	19	177,776	11	49,332
Withdrawn During Year										
Increases	2	468	6	93,709	4r	108,506r	4	141,323	5	98,620
Decreases	0	0	0	0	0	0	0	0	0	0
Denied During Year										
Increases	7	48,668	8	354,379	2	57,013	4	360,632	6	38,335
Decreases	0	0	0	0	0	0	0	0	0	0

Notes

This tabulation represents companies that have reported on a quarterly basis to Edison Electric Institute.

1. Does not include changes filed and approved, withdrawn, or denied during same quarter.
2. These figures are not in addition to the corresponding filed figures.

r = revised

servation and load management techniques, utilities in various parts of the country have been cancelling or deferring power plants. This not only portends the possibility of power shortages in the next decade—it also contributes to a continued dependence on imported oil, gas, and outdated, inefficient generating capacity. The availability of affordable electricity is dependent on the switch to less expensive fuels, the retirement of inefficient plants, and reduced financing costs. Therefore, a second major challenge facing the electric utility industry is to obtain sufficient rate relief to meet its obligation to provide adequate and reliable service at affordable rates.

Rate design for industrial customers is another area where we expect substantial activity in many states over the next few years. Industrial sales bore the brunt of last year's 1.5 percent decline in kilowatt-hour (kwhr) sales. For the third quarter of 1982 (latest available data), industrial kwhr sales were down 6.6 percent from the third quarter of 1981. The overall decline for this period was 2.2 percent. Nevertheless, revenue from industrial sales for the third quarter of 1982 was 8.1 percent higher than for the third quarter of 1981. For all customers, the corresponding increase was 6.9 percent.

Not surprisingly in this economic climate, there has been a reaction to this trend in several states. The Alabama and Connecticut commissions have directed utilities to develop action plans to reduce the energy costs to industries. In Iowa and Rhode Island, utilities have proposed rates that encourage industrial customers in their service territories. California has enacted legislation to insure special rate treatment for its steel industry. Arkansas abolished mandatory time-of-day rates as a "luxury" that its "citizenry can ill afford." It is too early to predict whether these admittedly isolated instances are harbingers of a nationwide trend.

A fourth challenge confronting the electric utility industry is the equally complex issue of "phasing in," or "trending" new plant into rate base to avoid the "rate shock" that comes from major additions to rate base. A positive plan of this sort has been accepted in principle by the Indiana Commission, which proposes to integrate the cost of the Marble Hill plant gradually into rates by a "stair-step or trended route." A negative type of plan, in that it proposes givebacks, is the "negative CWIP plan," which is being studied in Illinois and New York. Under this plan, Construction Work in Progress, or CWIP, previously included in rate base for a plant would be removed from rate base for corresponding periods after a plant came on-line. AFUDC would be restored on excluded amounts; rate base eventually would be increased by the amount of negative CWIP, plus the restored AFUDC. Although the merits of a phase-in must be decided individually, this type of plan can have disastrous financial consequences for a utility. The best way to avoid rate shock is to allow utilities a cash return on CWIP in their rate base. This method is in the long-term interests of ratepayers as well as utilities.

Some suggest that a logical remedy to these complex issues would be the creation of some form of regional regulatory agency with binding decision-making authority over specified electric power planning and regulatory matters in a multistate area. One such proposal is recommended in a draft report of the National Governors Association's task force on electric utility regulation. The NGA would have Congress enact legislation that:

- provides discretionary authority for the regional agency to regulate any or all of the following power supply planning functions: electricity demand and supply forecasts, reliability and reserve requirements, opportunities for increased power pooling and interconnections, and negotiation of electricity import and export agreements;
- provides discretionary authority for the regional agency to set wholesale and retail electric rates, site new power plants and transmission lines, and/or certify the need for new plants;
- provides discretion for a group of states to select whatever mix of these possible planning and ratemaking authorities best suits their needs and to determine if the supply plans adopted by the regional agency shall be binding on state

regulatory commissions and utilities;

- includes provisions that would exempt from such federal legislation any interstate compacts or agreements entered into by states from the requirement to obtain any (subsequent) additional Congressional approvals;
- provides for a financial assessment on electric power supplies to be utilized (at the option of the participating states) to support regional power planning and regulatory activities; and
- assures opportunities for public input in all aspects of the regional planning and regulatory process.

The NGA proposal is based on the political premise that utility regulation should be focused *exclusively* at the state and regional level and that groups of states should be given total discretion in designing the form of regional regulations best suited to meet their collective needs. At one extreme, the proposal could virtually eliminate or substantially weaken the Federal Energy Regulatory Commission's (FERC) role in promoting greater regional coordination in bulk power supply matters, without simultaneously obligating the states to assume this responsibility. At the other extreme, there is concern that the proposal might result in inconsistent and overlapping jurisdictional situations that will not provide the means to consider interregional and national interests in maintaining an adequate, reliable, and economic bulk power supply. The near-term option may be to work within the existing regulatory structure and state and federal laws to improve regional regulatory coordination on such matters as power plant siting, the need for power determinations, and ratemaking considerations.

Another suggestion to deal with the challenges confronting the electric utility industry is to move toward some form of deregulation. Some proponents argue that deregulation would eliminate regulatory costs and burdens, increase coordination, and promote competitive pricing of electricity. This recent surge of interest in the subject of deregulation led Edison Electric Institute to form an Ad Hoc Committee in June 1981. The committee's objective is to gain a comprehensive understanding of the various deregulation proposals, and it has made much progress toward that goal. The electric utility industry is approaching the issue of deregulation from a studied perspective, and with an open mind, seeking to identify clearly the specific issues presented by various deregulation proposals, assess the practicality of those proposals, and determine whether deregulation is feasible at all and, if so, whether it provides a cost-effective alternative to current regulation.

In addition to structural reform of the electric utility industry, either through regional regulation or some form of deregulation, interest is growing at the state and federal levels to incorporate mechanisms in the ratemaking process that encourage improved production performance. At the state level, commissions in Florida and Michigan, among others, have instituted power plant performance incentive programs; in Connecticut and Michigan, recovery of certain fuel costs have been tied to generating unit performance; and New York, New Jersey, and Illinois have construction cost control programs that include rewards and penalties. Some utilities, like Georgia Power, have been very interested in this area and are developing their own incentive programs. These involve compensating top management, and sometimes middle management, for contributing to the efficient production of electricity at high service levels.

A quick summary of these issues shows that the challenges for the 1980s are plentiful, complex, and, for now, perplexing. Rate relief, construction lead time and planning, industrial rates, and innovative ratemaking processes are just some of the challenges facing the electric utility industry business, consumers, and regulators throughout this decade. That these issues affect us all reflects the bottom-line challenge—to approach this decade full of problems and hurdles in a new way, with a new sense of being together in this business of providing the nation's energy needs. It will most assuredly take a new cooperative spirit among all of these parties to meet some of the difficult challenges we face, but, through such a cooperative effort, we can meet them successfully.

Nuclear Generation By State

Between 1976 and 1981 the number of states generating electricity with nuclear power increased from 24 to 27. Of those original 24 states, 19 showed increases in the level of nuclear generation, while 18 showed increases in the percentage of electricity generated by nuclear power. As shown on Table 1, both the level and share of nuclear powered generation increased at the national level. Placing nuclear's share in perspective, Table 2 shows by state and census division the percentages of total electricity generated from fuels and hydro in 1981.

In both 1976 and 1981 Illinois generated the most electricity from nuclear power. The largest increase in nuclear power generation occurred in Alabama, as it moved from being the fifteenth largest producer to being the second largest. Other states showing large increases were Arkansas, Florida, Maryland, Michigan, New Jersey, and Virginia.

The state with the largest percentage of its electricity being generated by nuclear power in both 1976 and 1981 was Vermont, with over three-fourths of its electricity generated from that source. Maine and Connecticut remained the only other two states generating over half of their electricity with nuclear power. The generation share from nuclear increased by large amounts in Alabama, Maryland, Michigan, New Jersey, Oregon, and Virginia.

Contributed by the Statistical department of Edison Electric Institute.

Table 1. States Ranked by Giga-Watt Hours of Nuclear Generation and by Nuclear's Share of Total Generation in the State: 1981 and 1976

	1981 Nuclear Generation				1976 Nuclear Generation			
	RANK	Giga-watt-Hours	RANK	As Percent of Total Generation In State	RANK	Giga-watt-Hours	RANK	As Percent of Total Generation In State
Alabama	2	23,643	11	31.6	15	4,214	20	7.7
Arkansas	14	9,075	9	35.9	17	3,858	7	31.6
California	24	3,207	26	2.5	14	4,808	23	4.0
Colorado	27	749	25	2.9		0		0
Connecticut	9	12,674	3	53.3	5	12,331	3	51.0
Florida	7	14,448	17	14.6	9	8,648	18	10.6
Georgia	15	7,235	20	11.7	16	4,134	19	8.9
Illinois	1	29,483	12	29.8	1	26,455	9	26.9
Iowa	25	2,204	21	9.7	22	2,479	16	14.0
Maine	19	5,212	2	56.3	12	5,929	2	65.5
Maryland	11	11,523	7	37.1	11	6,420	11	20.6
Massachusetts	22	4,331	18	13.2	19	3,664	17	11.1
Michigan	6	17,066	14	22.6	8	9,900	14	14.3
Minnesota	12	10,187	10	32.3	7	9,910	6	34.9
Nebraska	18	5,988	6	37.3	13	5,824	5	43.8
New Jersey	10	11,675	8	36.8	18	3,855	12	15.3
New York	4	17,446	15	16.5	4	15,660	13	14.4
North Carolina	17	6,246	22	8.7	21	2,511	22	4.1
Ohio	21	4,407	24	3.9		0		0
Oregon	16	6,424	16	15.9	24	2,103	21	5.6
Pennsylvania	8	14,277	19	12.2	3	16,427	15	14.3
South Carolina	5	17,328	5	42.0	2	17,850	4	47.2
Tennessee	20	4,704	23	8.0		0		0
Vermont	23	3,569	1	78.1	20	3,260	1	75.5
Virginia	3	17,819	4	47.5	10	7,740	10	20.9
Washington	26	2,042	27	2.0	23	2,405	24	2.3
Wisconsin	13	9,719	13	26.2	6	10,722	8	30.5
U.S. Total		272,681		11.9		191,107		9.4

SOURCE: EEI Statistical Year Books

Table 2. Energy Sources as Percentages of Total Generation from Fuels and Hydro by State and Census Division: 1981

State/DIVISION	Coal*	Fuel Oil	Gas	Nuclear	Hydro
TOTAL U.S.	52.6	9.0	15.1	11.9	11.4
Maine	—	23.3	—	56.3	20.4
New Hampshire	39.5	38.6	0.2	—	21.7
Vermont	1.1	0.2	0.2	78.1	20.4
Massachusetts	6.8	77.2	1.7	13.2	1.1
Rhode Island	—	73.8	26.2	—	—
Connecticut	—	45.6	—	53.3	1.1
NEW ENGLAND	5.9	53.6	1.0	33.5	6.0
New York	13.7	34.7	10.9	16.5	24.2
New Jersey	21.3	19.4	22.5	36.8	—
Pennsylvania	79.0	8.0	0.2	12.2	0.6
MIDDLE ATLANTIC	44.5	20.6	7.4	17.1	10.4
Ohio	95.6	0.4	0.1	3.9	**
Indiana	98.1	0.5	0.7	—	0.7
Illinois	63.7	5.4	1.0	29.8	0.1
Michigan	70.3	4.1	1.5	22.6	1.5
Wisconsin	66.4	0.4	1.1	26.2	5.9
EAST NORTH CENTRAL	80.4	2.4	0.8	15.5	0.9
Minnesota	63.6	0.3	1.3	32.3	2.5
Iowa	84.7	0.3	1.0	9.7	4.3
Missouri	97.1	0.3	1.2	—	1.4
North Dakota	85.8	0.2	—	—	14.0
South Dakota	33.5	0.2	**	—	66.3
Nebraska	52.7	0.3	2.2	37.3	7.5
Kansas	71.7	1.3	27.0	—	**
WEST NORTH CENTRAL	77.0	0.4	4.9	11.0	6.7
Delaware	55.7	37.6	6.7	—	—
Maryland	44.1	13.0	1.2	37.1	4.6
District of Columbia	—	100.0	—	—	—
Virginia	41.1	10.1	0.4	47.5	0.9
West Virginia	98.8	0.7	**	—	0.5
North Carolina	86.8	0.3	0.1	8.7	4.1
South Carolina	51.2	2.9	1.0	42.0	2.9
Georgia	83.6	0.7	0.3	11.7	3.7
Florida	21.3	47.9	16.0	14.6	0.2
SOUTH ATLANTIC	61.8	14.4	4.1	17.6	2.1
Kentucky	95.0	0.3	0.4	—	4.3
Tennessee	81.7	0.3	**	8.0	10.0
Alabama	60.1	0.1	0.2	31.6	8.0
Mississippi	44.7	11.9	43.4	—	—
EAST SOUTH CENTRAL	75.1	1.0	3.3	13.6	7.0
Arkansas	37.4	1.8	20.0	35.9	4.9
Louisiana	3.4	6.0	90.6	—	—
Oklahoma	32.0	**	66.4	—	2.6
Texas	34.2	0.3	64.9	—	0.6
WEST SOUTH CENTRAL	29.8	1.2	65.1	2.8	1.1
Montana	30.6	0.1	1.1	—	68.2
Idaho	—	—	**	—	100.0
Wyoming	96.5	0.3	**	—	3.2
Colorado	87.4	0.3	3.9	2.9	5.5
New Mexico	77.7	0.4	21.5	—	0.4
Arizona	69.3	0.7	13.3	—	16.7
Utah	92.4	0.3	2.0	—	5.3
Nevada	60.7	0.9	27.4	—	11.0
MOUNTAIN	70.6	0.4	9.5	0.4	19.1
Washington	6.8	**	**	2.0	91.2
Oregon	4.5	**	**	15.9	79.6
California	4.4	21.3	48.9	2.5	22.9
PACIFIC	5.3	10.2	23.3	4.3	56.9
Alaska	10.8	10.8	59.8	—	18.6
Hawaii	0.2	99.6	—	—	0.2
ALASKA & HAWAII	3.7	70.6	19.5	—	6.2

*Includes small quantity of geothermal, wood, and waste **Less than 0.1 percent

Managing Air Quality and Scenic Resources at National Parks and Wilderness Areas

Edited by Robert D. Rowe and
Lauraine G. Chestnut
Westview Press, 1983
Boulder, Colorado 314 pp.

By John A. Taylor, Ph.D.

One of the objectives of both the Clean Air Act and the Federal Land Policy and Management Act is to protect certain "visual experiences." Unfortunately, the science of protecting "visual experiences" had not caught up with the rulemaking when the Acts were passed in 1976 and 1977. How does one measure visibility—how well one can see—and visual resources—what one can see—and add those measurements together to define a "visual experience"?

The need for good scientific information on this subject has resulted in a flurry of research by both industry and government agencies, but the scientific progress has been hampered by the complexity of the issues involved. Because a visual experience involves an individual's psychological as well as physiological response to a scene, protecting that experience is not as easy as simply choosing a physical parameter to measure. It is necessary to tie this parameter into the response of the individual.

Managing Air Quality and Scenic Resources at National Parks and Wilderness Areas addresses this problem of protecting visual experiences. It is a collection of papers presented at the Visual Values Workshop held on May 10–12, 1982. The purpose of the workshop, which was jointly sponsored by the National Park Service, the Electric Power Research Institute, the American Petroleum Institute, and Edison Electric Institute, was "to focus upon the current state of research concerning how air quality impacts are perceived and valued by national park and wilderness visitors and how these values can be measured by researchers to assist the land managers with resource management decisions." Consequently, the book is a very technical document. It contains some of the most recent research on visibility and visual values.

Nonetheless, some portions of the book should be of interest to anyone concerned with environmental issues—the "Foreword" and Part VII, "Conclusions and Future Directions." Russell E. Dickenson, Director of the National Park Service, contributed the "Foreword." Although through much of it he merely describes in glowing detail the values of the national park system, he also calls for a balance of issues and values for areas outside the parks, "seeking answers which are workable, compatible and fair." Perhaps this philosophy will set the stage for more harmonious relations between local interests and the National Park Service. "Conclusions and Future Directions" summarizes the issues and the debates, the knowns and the unknowns, that were discussed at the workshop. Reading this section is about as close as one can get to being at the workshop. Here the editors best capture the tone and sense of direction of the workshop.

From an organizational viewpoint, the Visual Values Workshop was supposed to focus on those issues related to visibility as regulated by the Clean Air Act amendments, and the book's organization reflects that focus. However, both the organizers of the workshop and the editors of the book also included papers on the topic of scenic resource management or how to value and to preserve various scenes—a subject familiar to utilities who have had to place power lines in a manner to keep them hidden from the general public. Research on scenic resource management may be useful in attempting to determine the significance or adverseness of visibility degradation.

The book is divided into seven parts. Part I, "Defining the Experience," gives various rationales for why the visual experience is important. It is full of what may seem to many utility people to be emotionalism, double talk, glowing praise of the value of visibility, and forecasts of disaster if the experience is not preserved. However, even if they overstate the case for preservation, these papers are useful for understanding the rationale of the preservationist attitude.

Dr. Taylor is currently manager of the Water Quality Section of Virginia Electric and Power Company. Last spring, as Manager of the Air Quality Section at VEPCO, he spoke at the Visual Values Workshop on behalf of Edison Electric Institute.

Papers discussing how people value what they view are contained in Part II, "Measuring Visual Perceptions." Their objective is summed up best by a statement given in Ronald C. Henry's paper: "A basic goal of visibility research is to find reliable relationships between physical measurements of visibility and the corresponding appearance . . . [of a scene] as described by the human observer." Henry warns that what you measure is not what you see. Of course, he is correct, and this position is supported by the other papers in Part II, but it is obvious that researchers are making progress in identifying which relationships are reliable. For example, Douglas A. Latimer and others report on research that shows the pollution level and beauty of a scene do not always correlate. That is, in many cases, factors other than air pollution play much more dominant roles in contributing to or detracting from the beauty of a scene.

Part III, "Visual Resource Management Systems," brings a fresh viewpoint to the science of visibility. Traditionally the domain of the landscape architect, visual resource management combines art and science to determine how one values a scene or what changes in the landscape will do to the beauty of a scene. Although the final decision is qualitative, visual resource management schemes can assist builders, as well as federal land managers, to evaluate the actual or potential impacts of a facility on a scene's beauty.

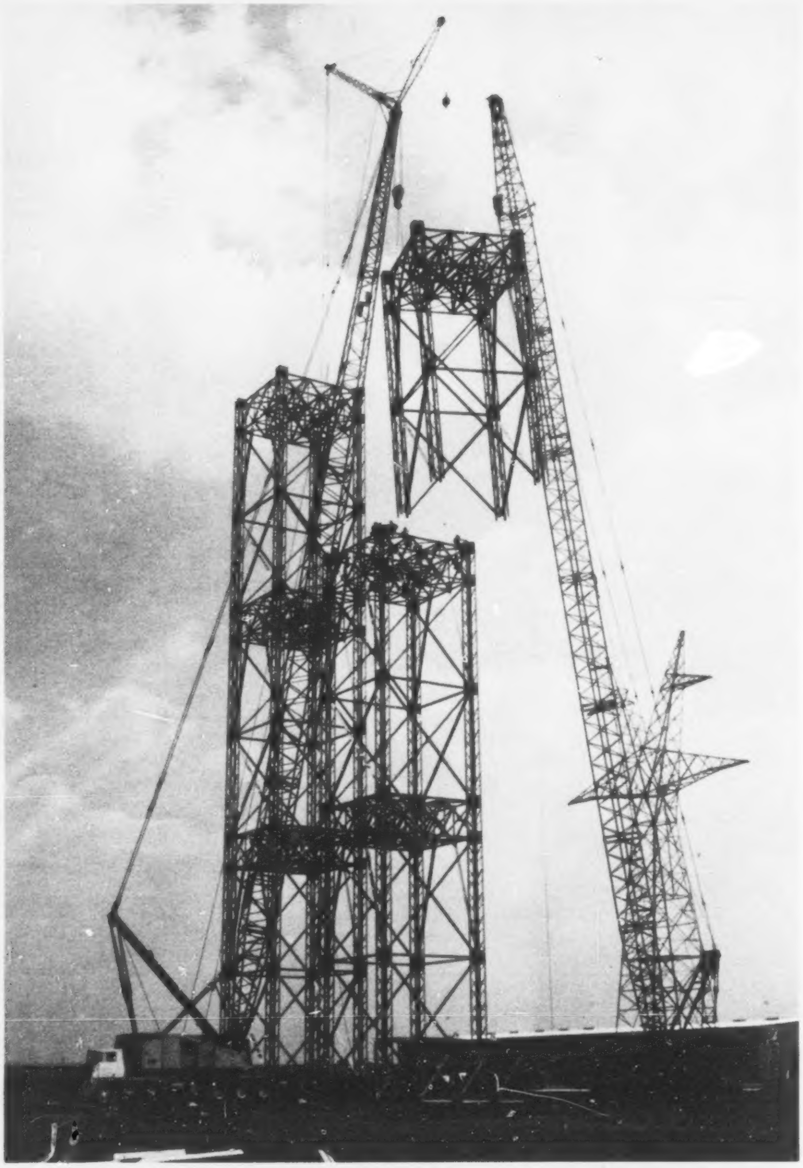
Entitled "Social and Psychological Approaches to Value Assessment," Part IV presents some interesting ideas about using the tools and methodologies of the social sciences to relate perceived changes in scenic quality to changes in the overall "visual experience." These eight papers primarily discuss various measurement methodologies and their implementation and shortcomings. The editors summarize the section well in their introduction to it: "This is a topic area where perspectives differ widely and much development in research methodologies, and their theoretical underpinning, is still needed."

Part V offers "Economic Approaches to Value Assessment." For example, one approach to measuring visibility in economic terms is to evaluate what a visitor to an area would pay to have better visibility. Several case studies are presented. In general, the user costs associated with visibility degradation are far less than the costs of controls on a generation station. However, other papers introduce another cost associated with visibility impacts—a preservation value. This is a value associated with knowing good visibility exists at specific locations. Although there is some controversy over this concept, many people believe that preservation value may be the greatest cost associated with visibility impairment.

"Management Perspectives and Case Studies," Part VI of the book, gives two nonfederal land managers' viewpoints on visibility regulation and presents two "case" studies. The perspectives offered by Edison Electric Institute and the Environmental Defense Fund are now somewhat outdated, but the case studies, although lacking in substance, do highlight the problems that need to be resolved prior to implementing any program.

Finally, Part VII discusses the conclusions reached at the workshop and suggests some future directions for the research efforts. It is worth repeating that the editors did an excellent job of summarizing the workshop discussions. One theme repeated throughout the discussions that found almost universal agreement is that adequate tools have not yet been found to enable the federal land manager (or anyone else) to make sound management decisions on the subject of visibility. Similarly, however, there is almost universal agreement that visibility (and scenic resources) is an important value to areas such as the Grand Canyon.

These conclusions have been reached during the peak of the debates on the Clean Air Act amendment. Perhaps this agreement at the technical level can be used as a starting point for achieving an agreement on how a good visibility law or regulation should be written.



The final portion of an 180-foot testing tower is lifted into place at the Transmission Line Mechanical Research Facility in Haslet, Texas.

Cutting the Costs of Transmission Towers

At a new research facility in Haslet, Texas, the Electric Power Research Institute (EPRI) is beginning a series of tests to determine how to construct transmission towers at lower costs without compromising reliability. Because very little data exists about the strength of transmission towers under dynamic loading conditions, such as gusting winds, towers have been conservatively designed as a matter of necessity. EPRI's goal is to determine exactly where utilities can economize in their designs and where they cannot.

"Ideally, management should be able to determine the level of reliability that is needed in its transmission towers, and engineers should be able to design for that level. This cannot be done now, and the result is that designs are often extremely conservative," said Richard Kennon, manager of EPRI's overhead transmission lines program.

The major challenge facing researchers stems from the fact that, so far, data obtained from field testing do not correlate with data predicted by laboratory tests. For example, wind tunnel tests to calculate the forces from blowing winds often give one reading; measurements taken in the field, using full-size transmission towers, show forces as much as 40 percent lower than the predictions.

"We don't know why the results are so different," Kennon said. "If we can find out, utilities will no longer have to use towers that are almost twice as strong as they need to be for satisfactory resistance to wind loads."

In applications for which accurate mathematical models have been developed, stresses are rarely in direct proportion to the loads that are imposed. As a result, full-scale testing is necessary to calibrate the analytical methods, Kennon noted.

Most transmission tower test facilities in the United States only conduct what are known as "proof" tests, or tests designed to prove that a tower will withstand certain stresses. There is no other facility in the world conducting research into techniques of predicting stresses on transmission towers on the same scale as the Transmission Line Mechanical Research Facility.

"Two years ago, when we established our transmission pole testing facility at Colorado State University, we could find reports of only 17 tests that had been conducted on transmission poles more than 50 feet high throughout the world," Kennon said. Since that time, EPRI has developed methods and equipment for utilities to use in conducting their own tests of wood transmission poles, adjusting for weather and other local conditions that may affect the pole's useful life.

Contributed by the Editorial Services Section of Edison Electric Institute.

EPRI expects it may take up to 10 years and cost $20 to $30 million to complete the research needed on transmission towers, ranging from soil testing and conductor stringing to maintenance procedures.

The potential savings to the industry are far greater, however. Electric utilities are expected to install more than 100,000 miles of new transmission lines during the next 20 years at a cost of about $30 billion. If the program at the Research Facility can reduce this cost by just one percent, it will pay for itself 10 times over.

During the experiments at the $9.5 million facility near Fort Worth, transmission towers, poles, and foundations will be subjected to a battery of tests simulating stresses that would be experienced in normal use. The "test pad" has 44 different cables that can be attached to individual tower components. Winches attached to the cables are capable of producing up to 100,000 pounds of tension each, and computers monitor each component to give a second-by-second record of the way the tower reacts to different loads. Both static and dynamic testing can be conducted.

A two-mile, unenergized test line will be used to measure stresses produced by "galloping," (up and down movements of the wires caused by light winds and ice) and by the uneven stresses that result when cables break or when ice warmed by the sun suddenly drops off a span of cable on one side of the tower but not the other side.

Another area at the facility, called the "sandbox," can be filled with different types of soil and used to test foundation construction.

Shakedown testing began in February, using a 345-kV tower donated by Texas Utilities Company. Utilities are being encouraged to participate in tests. Their participation will give researchers practical problems to incorporate into the overall project, and utility engineers will receive training in the use of the design tools being developed in conjunction with the facility.

Although the major goal of the facility is to validate and improve computer modeling techniques, a secondary goal is to explore the pros and cons of various tower designs and construction materials. Today, virtually all transmission towers are made of steel or aluminum. However, laminated wood, fiberglass-reinforced plastics, and some other composite materials offer potential cost savings.

Niagara Mohawk Pioneers Use of Ceramic Material

Five years ago, one-half-inch steel plates in Niagara Mohawk Power Corp.'s coal-handling equipment were wearing out in approximately three weeks' time, and the company was spending millions of dollars to replace them.

Not so anymore. In 1978, a quality assurance engineer at the firm's C. R. Huntley Steam Station in Buffalo introduced the company to a new ceramic material known as *fused aluminum oxide*. The material was cemented to existing steel plates on a trial basis. Now, five years later, the material is smoother than when it was installed. Coal flows faster on it and chute-plugging, freezing, and other coal-handling problems have been eliminated.

The Quality Assurance Engineer, John Daniels, calculates that over a 20-year span, the company will save nearly $90 million by using the ceramic material in highly abrasive areas in its coal-handling systems.

Daniels also convinced the company to line the interior walls of the steel pipe used to move ash slurry with the fused aluminum oxide. It is expected that this liner will provide between 15 to 20 years' service without any rotation. Without the liner, the pipe got 4 to 6 years' life if rotated annually to permit new wear areas to be exposed to the abrasive slurry ash. The liner also eliminates the need for major load reductions and, in some instances, shutdowns for repair.

Other parts of the coal-moving systems in which Niagara Mohawk is experimenting with ceramic materials include the classifier liners in coal pulverizers, blower exhaust liners, long and short radiuses in bend liners, burner liners, and burner directional plates in feed systems.

Growth in Number of Investors Slows

The number of investors owning shares of electric utility common stock rose 1.3 percent in 1981, the smallest annual increase since Edison Electric Institute began tracking the number in 1975 (see Table 1). Over the same period, however, the number of common stock shares outstanding jumped from 3.512 to 3.937 billion, an increase of 11.8 percent.

These industry totals were aggregated from the listings of individual electric utility data published in Moody's *Utility Manual* (volumes 1 and 2). Because some investors own shares of more than one utility, they are listed more than once in the *Manual.* Consequently, the aggregated total for the number of industry stockholders is somewhat high.

Table 1. Number of Stockholders in Electric Utility Industry by Years

Year	Number of Stockholders	Percent Change
1981	8,535,000	1.3
1980	8,426,000	4.7
1979	8,044,000	2.9
1978	7,818,000	8.9
1977	7,177,000	5.1
1976	6,831,000	4.6
1975	6,528,000	43.5 (1975/1970)
1970	4,549,000	—

Contributed by the Finance department of Edison Electric Institute.

Earnings Per Share Post 5.9 Percent Third Quarter Gain

Earnings per share of the investor-owned electric utility industry increased to 90 cents during the third quarter of 1982, up 5.9 percent over the third quarter of 1981. Third quarter net income available for common, $3,871 million, increased 16.2 percent, but a 10.5 percent increase in shares outstanding diluted the gain in earnings per share. The growth in earnings reflects the continuing reinvestment of earnings by common stock shareholders and the higher return on equity being authorized by commissions. The increase in electric operating revenues, combined with a lesser increase in electric operating expenses, was one of the main contributors to the net income gain. Also, AFUDC jumped 24.7 percent in the third quarter of 1982 compared to the third quarter of 1981. These factors were offset somewhat by a 12.2 percent increase in interest on long-term debt and an 11.1 percent increase in preferred dividends.

For the 12 months ending September 30, 1982, earnings per share were $2.97, a 12.9 percent increase over the prior one-year period. For the one-year period, AFUDC contributed more than half of the net income increase. Improvements in electric and other utility operating income, other income, and extraordinary items also contributed.

Third quarter revenues increased 6.2 percent over the prior year's third quarter to $28,278 million. The increase resulted from rate increases granted during the past year, but it was offset slightly by the drop in kilowatt-hour sales. Edison Electric Institute estimates that third quarter 1982 kilowatt-hour sales of the investor-owned electric utilities decreased 4.1 percent compared to the third quarter of 1981. The recession, cooler than usual weather, and conservation account for most of the drop.

Electric operating expenses during the third quarter were $22,740 million, an increase of 5.6 percent over last year's third quarter. Electric operating expenses were 80.4 percent of electric operating revenues. In the third quarter of 1981, the ratio was 80.9 percent. Third quarter 1982 fuel expense was 43.7 percent of electric operating expenses, compared to 49.3 percent in the third quarter of 1981. The 5.6 percent drop was due to a lower level of electricity generation and the lower costs of some fuels. Because of lower interest rates and a lesser volume of short-term debt outstanding, other interest expenses and charges decreased.

AFUDC as a percentage of net income before preferred dividends increased in the third quarter of 1982 compared to the third quarter of 1981 and also increased on a year-to-year basis. Third quarter 1982 AFUDC was 40.1 percent of net income before preferred dividends; for third quarter of 1981, it was 37.2 percent. For the year ending September 30, 1982, AFUDC was 45.0 percent of net income before preferred, up from 43.8 percent for the previous one-year period.

The improvement in net income led to continuing improvement in interest coverage during the quarter and year. Coverage before income taxes and with AFUDC was 3.20 times in the third quarter of 1982, while it was only 2.99 times in the third quarter of 1981. For the year ending September 30, 1982, coverage was 2.71 times, up from 2.53 times for the year ending September 30, 1981.

Table 2, the consolidated income statements, is based on unaudited reports received from electric utilities. These reports accounted for 94 percent of the industry's revenues. Data were expanded to represent the entire investor-owned electric utility industry.

Table 2
INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY
STATEMENT OF INCOME
(Unaudited, Millions of Dollars)

	Three Months Ended			Twelve Months Ended		
	September 30,		%	September 30,		%
	1982	1981 (R)	Change	1982	1981 (R)	Change
Total Electric Operating Revenues	$28,278	$26,619	6.2	$100,378	$90,606	10.8
Electric Operating Expenses						
Fuel	9,935	10,627	(6.5)	36,809	36,568	0.7
Other Operation & Maintenance Expenses	6,296	5,215	20.7	24,172	19,916	21.4
Depreciation & Amortization	1,897	1,723	10.1	7,336	6,583	11.4
Taxes Other Than Income Taxes	1,891	1,773	6.7	7,035	6,475	8.6
Income Taxes (Federal & Other)	1,535	1,295	18.5	3,237	2,120	52.7
Provision For Deferred Income Taxes—Net	601	484	24.2	1,875	2,158	(13.1)
Investment Tax Credit Adjustments—Net	585	423	38.3	2,053	1,010	103.3
Total Electric Operating Expenses	22,740	21,540	5.6	82,517	74,830	10.3
Electric Utility Operating Income	5,538	5,079	9.0	17,861	15,776	13.2
Other Utility Operating Income	64	39	64.1	1,108	918	20.7
Total Utility Operating Income	5,602	5,118	9.5	18,969	16,694	13.6
Other Income & Deductions—Net	433	405	6.9	1,822	1,538	18.5
Allowance For Other Funds Used During Construction	1,044	776	34.5	3,738	2,885	29.6
Total Income	7,079	6,299	12.4	24,529	21,117	16.2
Interest On Long-Term Debt	2,932	2,613	12.2	11,211	9,781	14.6
Other Interest Expenses & Charges	370	456	(18.9)	1,545	1,620	(4.6)
Allowance For Borrowed Funds Used in Construction (Cr.)	(766)	(676)	13.3	(2,907)	(2,437)	19.3
Total Interest & Charges	2,536	2,393	6.0	9,849	8,964	9.9
Net Income Before Extraordinary Items	4,543	3,906	16.3	14,680	12,153	20.8
Extraordinary Items	(34)	—	—	91	(5)	—
Net Income	4,509	3,906	15.4	14,771	12,148	21.6
Preferred Stock Dividends Declared	638	574	11.1	2,442	2,271	7.5
Net Income Available For Common	3,871	3,332	16.2	12,329	9,877	24.8
Earnings Per Share*	$0.90	$0.85	5.9	$2.97	$2.63	12.9

*Based on average shares for each quarter. Shares adjusted to reflect recent stock splits.

NOTE: The income statement is a "net" or "consolidated" statement. The duplicative effect of including resale revenues by one investor-owned electric utility to another has been eliminated.

CALENDAR OF MEETINGS
Edison Electric Institute

When
What
Where
Who to Contact
(Call 202/828-7400)

April 10–22
Executive Management Program
Hershey, Pennsylvania
Frances Palladini

April 18–20
Construction Workshop
New Orleans, Louisiana
Eric Haskins

April 18–20
Fire Protection Committee
San Antonio, Texas
James Evans

April 18–21
Labor Relations Conference
Indianapolis, Indiana
Ed Bomsey

April 20
CS&M Executive Advising Committee
San Francisco, California
Charles Taylor

April 20–22
CS&M Annual Conference
San Francisco, California
Charles Taylor

April 25–27
Nuclear Operations Committee
St. Francesville, Louisiana
Suzanne Phelps

April 25–27
Meter & Service Committee
Oklahoma City, Oklahoma
David Soffrin

April 25–27
Compensation & Benefits Committee
Boston, Massachusetts
James Stroop

April 27–30
Legal Committee
Gleneden Beach, Oregon
Robert Baum

May 2–3
Rate Research Committee
Denver, Colorado
David Owens

May 2–4
Purchasing & Stores Committee
San Diego, California
Martin Gordon

May 2–4
Safety & Industrial Health Committee
New Orleans, Louisiana
Melodye Turek

May 2–4
Prime Movers Committee
Denver, Colorado
James Evans

May 3–6
A.G.A.-EEI Customer Services Committees
Kansas City, Missouri
Robert Griffin

May 4–6
Security Meeting
Baltimore, Maryland
Eric Haskins

May 4–6
Statistical Committee
Minneapolis, Minnesota
Thomas Daugherty

May 9–11
Consumer Affairs Committee
Dearborn, Michigan
Charles Taylor

May 9–11
Electrical System & Equipment Committee
Atlantic City, New Jersey
Jamei Goellner

May 11–12
Governmental Affairs Conference
Washington, D.C.
Robert Dolan

May 11–13
A.G.A.-EEI Information Systems Committees
New Orleans, Louisiana
Ralph Palmigiano

May 12–13
Finance Committee Annual Meeting
New York, New York
Ted Gradin

May 16–18
System Planning Committee
St. Louis, Missouri
Jamei Goellner

May 16–18
A.G.A.-EEI General & Plant Accounting Committees
San Diego, California
George Brown

May 17–20
Transmission & Distribution Committee
Charleston, South Carolina
David Soffrin

May 17–19
Hydraulic Power Committee
Roanoke, Virginia
James Evans

May 18–19
Electric Power Survey Committee
Denver, Colorado
Thomas Daugherty

May 18–20
Audio-Visual Task Force
St. Louis, Missouri
Hal Dunham

May 19–20
Public Information Forum
St. Louis, Missouri
Patti Johnson-Rogers

May 25–27
Environment & Energy Committee
Seattle, Washington
Victoria Hull

May 25–27
A.G.A.-EEI Internal Auditing Committees
Salt Lake City, Utah
Marshall Baker

May 25–27
National Conference of Electric Utility Educators
Kansas City, Missouri
Walt Purdy

June 6–8
51st Annual EEI Convention
Minneapolis, Minnesota
John Mahoney

June 21–22
Seminar on Current SEC Developments
New York, New York
Ted Gradin

June 27–29
A.G.A.-EEI Budgeting & Financial Forecasting
Atlanta, Georgia
Lowell Klosky

June 27–29
A.G.A.-EEI Depreciation Accounting Committees
Williamsburg, Virginia
George Brown

July 18–22
Tax Seminar
Dallas, Texas
Ted Gradin

August 15–17
Training Directors' Institute
Atlanta, Georgia
Frances Palladini

September 19–21
Annual Roundtable Conference
Chicago, Illinois
Frances Palladini

October 4–6
Electric Vehicle Council
EV EXPO '83 Electric Vehicle Exposition & Conference
Dearborn, Michigan
John Makulowich

October 5
CS&M Executive Advisory Committee
Albuquerque, New Mexico
Charles Taylor

October 6–7
CS&M Division Executives' Symposium
Albuquerque, New Mexico
Charles Taylor

October 10–12
Financial Conference
Palm Beach, Florida
Ted Gradin

November 7–9
Claims Committee
San Diego, California
Robert Baum

November 16–18
A.G.A.-EEI Information Systems Conference
Kansas City, Missouri
Ralph Palmigiano

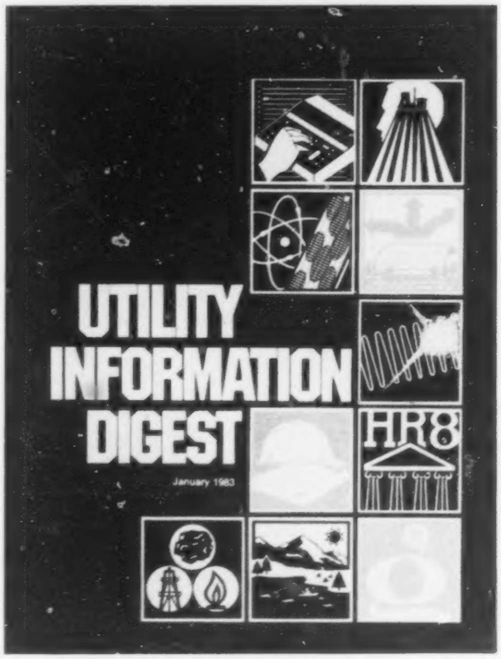
GET A HEAD START ON TOMORROW

The EEI "Personal Database" gives you vital background and a look into the future

It is increasingly difficult to keep up with the deluge of publications we all feel we should read. They range from the many trade magazines—*Electrical World, Electric Light & Power*—to the general news publications—*Time, Business Week*—to the thought leading publications—*Fortune, The Economist.*

Not only do we feel snowed by the increasing volume of information being transmitted, but information is being made available to us at a faster rate than anyone can be expected to absorb it. Meanwhile, the pace of events is shortening the lead time for developing well-researched decisions, and government regulation, deregulation, public attitudes, corporate responsibility, and other factors are adding difficult—sometimes touchy—considerations.

There's a problem—and Edison Electric Institute has come up with something to help—a monthly service called *Utility Information Digest*. The *Digest* tracks at least 100 of the most widely-read magazines and periodicals affecting the industry and prepares abstracts of significant items. What makes the service most valuable is its thorough cross reference index. By utilizing keywords, *Utility Information Digest* subscribers are able to locate all articles on a vast number of topics.



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culture (kul′ chər) *n: the ideas, customs, skills, arts, etc. of a given people in a given period . . .*

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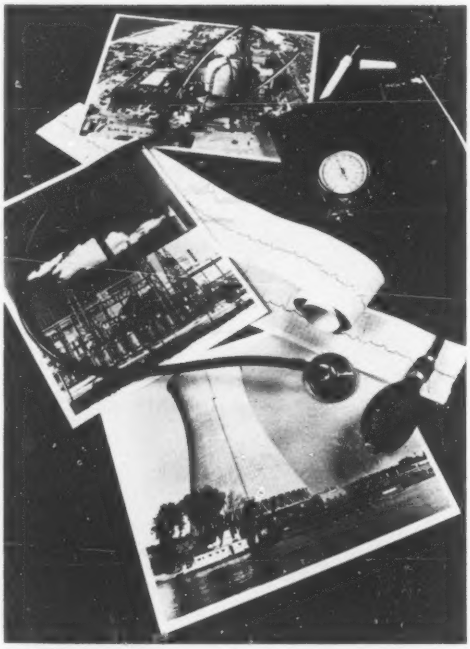

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COVER
While the full power of American philanthropy has not yet turned to the fundamental problem of protecting the country's ecologically valuable natural areas and the plant and animal life they support, more and more corporations are taking advantage of opportunities to assist.

Illustration by Michael J. McGurk

The Best Buy in Corporate Charity

By William D. Blair, Jr.

Electric utilities lead business in supporting conservation

When Georgia Power Company a decade ago gave nearly a million dollars worth of real estate to The Nature Conservancy, it was the start of something big—an effective nationwide partnership between business and conservation.

The Georgia Power property lay along the magnificent Chattahoochee River on Atlanta's city line. Years before, the company had bought the 158 acres for a hydroelectric generating site, but building a dam had never proven feasible. In 1972, when The Nature Conservancy began seeking undeveloped land along the Chattahoochee's banks for a wilderness park, the utility took the opportunity to turn a dead asset into a charitable gift with benefits for both the company and the public.

Thanks to Georgia Power's lead, the Conservancy was then able to acquire the other private properties that today make up the Chattahoochee River National Recreation Area, which is administered by the National Park Service. Each year, the scenic wild river draws over half a million nature and watersport enthusiasts from the Atlanta area alone to its miles of undisturbed woods and waters.

This kind of positive involvement with a conservation group was unheard of in the corporate community in the early 1970s. But with this example, business was quick to discover that an investment in conservation could produce maximum output for the charitable dollar.

Since Georgia Power, the list of electric utilities that have supported The Nature Conservancy in particular has grown long. In fact, our experience suggests that nearly every major industry in this country—including oil, forest products, chemicals, transportation, communications, banking, and insurance, among others—has become beneficially involved in conservation.

More than 50 corporations, for example, have chosen to give the Conservancy outstanding natural areas worthy of preservation and collectively valued at over $75 million. Others have sold the Conservancy significant lands at prices far below fair market value. Literally hundreds of other companies have donated millions of dollars in cash to help protect important land and water.

Buying Time for Our Life Support System

The sole business of The Nature Conservancy is to identify and preserve the most ecologically valuable natural areas remaining and the full array of plant and animal life they support. Private and nonprofit, the Conservancy is the only national conservation organization whose resources are wholly devoted to this mission, one which it has pursued since its incorporation in 1951. In 32 years, it has brought under protection nearly 2 million acres of the nation's finest and most unaltered wetlands, barrier islands, virgin forests, unplowed prairies, and other natural systems, along with hundreds of species of flora and fauna which would otherwise be facing early extinction.

Most often, protection is achieved by purchasing the land on the open market. Donations, conservation easements, long-term leases, and management agreements with landowners are other preservation tools. The Conservancy has no condemnation power, wants none, and prides itself in doing its work in a businesslike and noncontroversial manner.

William Blair is President of The Nature Conservancy.

Do we need to preserve natural areas?

Yes, we do, and fast. The truly natural areas not now protected will soon be gone. With the equivalent of a new city of 100,000 people springing up in this country every 16 to 17 days, the pressures on the land are rising geometrically.

Our topsoil is washing down our rivers by the hundreds of million tons per year.

Worldwide, scientists estimate at least one, possibly several, species each day on the average is becoming extinct, mostly from loss of habitat.

We have lost half of all our wetlands, most of them in our own lifetime.

Our native grasslands have dwindled. The tallgrass prairie, once a million square miles or more of North America, exists today only in scattered fragments measured in acres.

Our lakes and rivers are being invaded by exotic (non-native) species and polluted and destroyed as natural systems.

As a result of these trends, we are losing our genetic resources—plant and animal species—at an alarming rate. Worldwide, scientists estimate at least one, possibly several, species each day on the average is becoming extinct, mostly from loss of habitat. By the end of the century, there will be one or more species lost every *hour*. In a word, the global ecosystem—the capacity of the earth to support life, all life, including our own—is eroding.

Because we don't fully understand how the global system works, we can't predict the consequences of this erosion for our atmosphere, our climate, or our clean fresh water supply, though there is growing scientific concern.

We do know, however, that the loss of species, which is irreversible, is an unprecedented threat to our agriculture, which is heavily dependent on plant diversity to sustain and enlarge the world's food supply; to our medicine, which counts on plant life for existing and future drugs to help control major diseases; and to many industries presently or potentially based on natural products.

The reduction of the world's gene pools is all the more costly because of the new science of genetic engineering, which is just beginning to exploit the enormous potential of the genetic material which only nature can create.

For all these reasons, the Baird Professor of Science at Harvard University, Edward O. Wilson, spoke for the scientific community recently when he referred to the loss of natural habitats as "the folly our descendants are least likely to forgive us. . . ."

While the full power of American philanthropy has not yet turned to this fundamental problem, more and more corporations are taking advantage of opportunities to assist.

Preserving Corporate Land

Electric utilities are major landowners. In their real estate portfolios, some of them have identified ecologically valuable property not suitable for their current needs. Georgia Power disposed of such surplus acreage through its charitable gift to the Conservancy.

Gulf States Utilities did the same. Gulf States joined with Temple-Eastex, a subsidiary of Time Inc., in preserving a portion of the Big Thicket area of east Texas. The 2,138 acres of arid sandylands, worth $1.6 million, that Temple-Eastex donated to The Nature Conservancy in 1977 had long been recognized by scientists as a biological crossroads of North American ecosystems.

One naturalist wrote of it, "There are few places on the face of the globe where you can stand in one spot, and just by turning your body a bit, see a swamp that might remind you of the Everglades, a 'desert' bristling with cactus and Spanish-dagger yucca, open floor forest typical of the Appalachian mountains, and seepy Southern pinelands."

At a public dedication, the preserve was named the Roy E. Larsen Sandyland Sanctuary after the late Vice Chairman of Time Inc., a pioneer private-sector conservationist. To make the preserve complete, Gulf States Utilities in 1979 added the gift of a 40-acre power line right-of-way worth $50,000 that cut across the sanctuary, and later pledged $20,000 for research and management at the preserve. The Sandyland Sanctuary is now one of the Conservancy's models.

In the Midwest, Northern States Power, which is headquartered in Minnesota, donated 182 acres of forested islands in the Mississippi River. Today the land is part of the state's wild and scenic river system. Wisconsin Power & Light gave land to help protect a roosting site at Ferry Bluff for the endangered bald eagle. In the East, Pennsylvania Power & Light donated 93 acres at the Seven Tubs area, where a locally rare orchid grows in a narrow wooded gorge. Niagara Mohawk gave a small research forest on New York's Hudson River.

Electric utilities have been joined by other U.S. industries. One year after Georgia Power's decision on the Chattahoochee property, Union Camp Corporation, a major forest products company, donated 49,000 acres of the famous and ecologically diverse Great Dismal Swamp on the North Carolina-Virginia border. On the occasion, Union Camp's Chairman, Alexander Calder, Jr., commented, "There is no doubt in my mind that this action represents the highest and best use for the property. The company was able to take the normal charitable tax deduction to which all taxpayers, corporate and individual, are entitled."

The Great Dismal Swamp tract had been appraised at $14 million. Calder pointed out "that the interests of the public and an investor-owned corporation can indeed be compatible."

Later, Union Camp gave the Conservancy another wetland, 16,600 acres of Georgia's important Okefenokee Swamp, home to alligators, river otters, pileated woodpeckers, and Walt Kelly's comic strip character "Pogo." The tract was valued at $6.5 million in 1978. Like the Great Dismal Swamp and a number of other Conservancy acquisitions, this property was then transferred to the federal government, in this case to the U.S. Fish & Wildlife Service for inclusion in the Okefenokee National Wildlife Refuge.

To date, Union Camp has made nine land gifts for preservation. Most recently, in 1982, the company donated 176 acres in North Carolina known as Camassia Slopes, worth an estimated $130,000 in cash but priceless for numerous wildflower and bird species which are increasingly rare and endangered in that region.

International Paper is another member of the forest products industry that has given the Conservancy important land, six tracts in all, ranging from 26,000 acres in Georgia to 1,200 acres along the Appalachian Trail in Maine. Chemical companies like Union Carbide, oil companies like Shell, communications companies like International Telephone and Telegraph, and railroads like the Chessie System have done the same.

Where an outright gift of land is not feasible, the Conservancy encourages a "bargain sale"—that is, sale at less than fair market value. Under the tax laws, the amount of the reduction below market value in a sale to a charity qualifies as a charitable deduction. For example, the St. Regis Paper Company made a bargain sale to the Conservancy of 6,000 acres of habitat for the only known colony of the Mississippi sandhill crane. The selling price was $3,775,000, some $700,000 under the appraised market value; the $700,000 difference, in effect, was a charitable donation.

Recently, the Conservancy acquired an option from the Central Vermont Public Service Corporation for the purchase of Tinmouth Channel, a 1,100-acre wetland significant for its waterfowl, furbearing animals, and endangered plants. The property's fair market value has been estimated at $166,000, but the electric utility is selling the tract for $100,000 and making a charitable gift of the difference.

Landowners also can help preserve important natural areas without giving up title to them. Leases and management agreements offer two alternatives. For instance, International Paper signed a "protection and lease agreement" with the Conservancy to safeguard the site of a rare golden eagle

Tinmouth Channel, a 1,110-acre wetland significant for its waterfowl, furbearing animals, and endangered plants, was recently acquired by the Conservancy from Central Vermont Public Service Corporation at a price well below its fair market value.

nest on its property in New York's Adirondacks. The Conservancy leases and manages a 500-acre area surrounding the nest. International Paper continues to own the land and pay the real estate taxes. Similar arrangements have been made for special tracts owned by Ford Motor Company, General Electric, and several major railroads.

Conservation is Popular

Even for companies that do not own important natural areas, land and water conservation projects offer attractive opportunities for the community service dollar. Few civic projects have so caught the enthusiasm of the people of North Dakota, for example, as the current campaign to purchase Cross Ranch, 5,000 acres of prairie and scarce riparian woodland spread along 8 miles of the Missouri River, 30 miles north of Bismarck. This extraordinary property hosts the pronghorn antelope, bobcat, ferruginous hawk, and other rare species in a natural environment like that of centuries ago.

An ambitious project now nearing its $2.7 million goal, the preservation of Cross Ranch has attracted contributions from 6,400 individual North Dakotans—1 percent of the state's population. The corporate sector has been no exception. Montana-Dakota Utilities and its board of directors made a combined $50,000 contribution; $100,000 gifts came from Great Plains Gasification Associates and the foundations of Amoco and Burlington Northern; and other exceptional contributions were made by Northern Border Pipeline, Gulf Oil, Northwestern Bell Telephone, and others. Otter Tail Power and Northern States Power delivered $15,000 and $10,000 checks, respectively, and additional contributions came from Basin Electric Cooperative and the United Power Association. In total, approximately 125 corporations contributed to the Cross Ranch project.

To date, 32 state conservation agencies, in cooperation with the Conservancy, have developed data bases to determine land and resource preservation priorities through a continuously updated repository of ecological information.

Here in the Washington, D.C., area, where the Conservancy is headquartered, the campaign to protect the Mid-Atlantic region's largest great blue heron rookery at Nanjemoy, Maryland, attracted similar community enthusiasm. Both Baltimore Gas & Electric and Potomac Electric Power Company supported the project, and BG&E joined in the follow-up campaign for the Nassawango Creek bald cypress wilderness on the state's eastern shore. Idaho Power, Commonwealth Edison, Iowa Power & Light, Virginia Electric and Power Company, Puget Sound Power & Light, and Rochester Gas & Electric are all among the donors to recent natural area preservation projects in their own service areas.

In Pennsylvania, Pennsylvania Power & Light became a central figure in the local Nature Conservancy chapter's $700,000 drive to establish a program to find and preserve that state's remaining unprotected rare areas. PPL kicked off the campaign by arming the chapter with free promotional materials and later, when donations began pouring in, gave $22,500 itself.

In Florida, saving the manatee is one of the state's most popular causes. Florida Power & Light has been intensively involved in it because the marine mammal frequents the company's warm water effluents as well as the other coastal waters of the peninsula. In January of this year, FPL donated 500 sets of limited edition manatee prints to be sold to raise money for the Conservancy's Crystal River Manatee Sanctuary. Sale of the prints, nearly complete, is bringing in $25,000 toward the $425,000 needed and nearly in hand to cover the purchase of 14 islands in the Crystal River where the endangered manatees congregate.

Corporate Planning Benefits

As electric utilities were among the first to recognize, the Conservancy's science-based information gathering offers a major asset for corporate as well as nonprofit and governmental planning.

Nine years ago, Conservancy scientists devised a unique inventory process to pinpoint the nation's elements of natural diversity—the threatened natural systems, communities, and species in need of protection to prevent their total disappearance. The inventories, called natural heritage programs, have proceeded systematically on a state by state basis, mapping areas both protected and unprotected. To date, computerized data bases for 32 states have been developed in cooperation with individual state governments, which typically take over and maintain the inventories once they are established. The programs provide a continuously updated repository of ecological information.

With this data, the Conservancy and state conservation agencies can determine land preservation priorities and can focus resources on the most important areas. Use of the data is also open to others who want an objective, scientific evaluation of lands and ecological resources.

Electric utilities in particular have enthusiastically applied this tool in land management and in long-range planning for the expansion of facilities. In letters to chief executives at other power companies, Hugh A. Barker, Chairman of Public Service Company of Indiana, told why all of Indiana's investor-owned electric utilities joined together to give $48,000 to help the Conservancy start a natural heritage inventory in their state.

Barker wrote, "PSI supports the Indiana Natural Heritage Program because in this state there is a serious absence of data relating to rare plant and animal species and the ecosystems which contain them. The absence of this data has caused disagreement among the corporate community, the environmental community, and the state and federal government, resulting in costly and unnecessary delays in important development activities."

He went on to say that "Our corporate support of the program is justified by the use of the data as authoritative and reliable information necessary in siting plants, substations, and transmission lines." Furthermore, he said, "We believe the Indiana Natural Heritage Program is a useful tool which strikes a balance between the state's need to preserve the best remaining examples of Indiana's natural lands while permitting responsible development of the state's natural resources."

The Indiana & Michigan Electric Company, Indianapolis Power & Light, Northern Indiana Public Service, and Southern Indiana Gas and Electric were the other power companies involved in funding the Indiana inventory under the auspices of the Indiana Electric Association.

From this data base, Indiana & Michigan Electric learned in 1981 that the Maryland meadow beauty, an endangered plant thought extinct in the area since 1916, grew on the proposed site for the Rockport generating station—the only known location of the plant in Indiana. As part of its land use plan, the utility took steps to protect the area where the meadow beauty grows and notified the Conservancy of its intent to protect the rare plant while building and operating the power plant on the property. This sort to voluntary conservation action by private landowners is actively encouraged by the Conservancy as an alternative to acquisition of the land.

. . . voluntary conservation action by private landowners is actively encouraged by the Conservancy as an alternative to acquisition of land.

Likewise, the Florida heritage program saved the Seminole Electric Cooperative substantial money, time, and manpower just two years ago. The Cooperative was considering a site for a new coal-fired power plant along the Apalachicola River and was not aware that the steep ravines of the proposed site, a place known locally as "the Garden of Eden," sheltered several rare species, including the indigo snake, the United States' only threatened reptile, and the torreya, an evergreen found nowhere else in the world. Because Seminole checked with the heritage data bank and discovered these facts, the company was able to avoid controversy and costly delays in building the power plant and to make an important contribution to conservation by selecting an alternative site for the plant.

Minnesota is another state where heritage information has drawn strong interest from electric utilities. To help get the inventory started, Northern

Holding samples of limited edition prints donated by Florida Power & Light for sale by the Conservancy, left to right, FPL Director of Environmental Affairs Sam Tucker, Florida Governor Bob Graham, Conservancy State Director Michael Green, and Conservancy Florida Chapter Trustee Robert Rhodes

States Power, Minnesota Natural Gas, and the Potlatch Corporation jointly put up $39,000. Later, Northern States allied with Interstate Power Company, Minnesota Power, Otter Tail Power, two cooperatives, and two power associations through the Minnesota/Wisconsin Power Suppliers Group to invest another $25,000 in the Minnesota program.

The story is the same for electric companies in Massachusetts, Iowa, Colorado, Arkansas, and California. These donors and other utilities using the data banks comment on the heritage system as "the most specific and consequently the most helpful" among services offered by environmental agencies.

The same benefits have been recognized by a number of other industries. State inventory programs now receive thousands of inquiries each year and heritage data has proven useful in many fields. Support has come from Amoco, Exxon, Pennzoil, Union Pacific Railroad, Gannett, and others. The consulting firm of environmental engineers Dames and Moore, for example, relies heavily on the Mississippi inventory to serve its clients' purposes there, including the assessment of several proposed petroleum, nuclear power, and other major industrial facility sites.

In fact, many corporations consult the Conservancy's natural heritage files before submitting environmental impact statements for proposed projects to state government. The states then use the same data to review the documents. By alerting its many users to potential conflicts concerning the small fraction of the landscape with the most ecological value, the system permits resolution of problems on a timely and factual basis.

Lending Your Good Name

Another way in which companies today are helping conservation and the Conservancy is by signing up as "corporate associates" of the organization, thereby publicly endorsing and supporting its preservation work. The cost is minimal: participating companies are asked to contribute at least $1,000 to the Conservancy's annual operations, and many voluntarily contribute more, up to a current high of $10,000 a year. To date, there are some 400 corporate associates of The Nature Conservancy from New York to Honolulu (including 13 electric utilities), representing a breadth of U.S. business support which relatively few nonprofit organizations, and probably no other conservation group, enjoy.

Of our corporate associates, about 25 percent are among the Fortune 500 companies, but as many as 49 percent of them are too small for the Fortune 1300—which means that smaller, primarily local and regional, businesses also are recognizing the importance of land conservation.

The operating funds they contribute help to meet such continuing needs as the management of the Conservancy's 700 nature preserves across the country, ensuring appropriate public use along with the long-term protection of their natural qualities.

The fruitful partnership between the business community and The Nature Conservancy is in large measure the doing of a distinguished 36-member Corporate Relations Committee, cochaired by a present and a former Conservancy board member, John H. Filer, Chairman of Aetna Life and Casualty Company, and Dan W. Lufkin, Chairman of Questor Corporation. Among other members are Roy D. Chapin, Chairman of American Motors' Executive Committee; Alexander Calder, Jr., Chairman of Union Camp; David M. Roderick, Chairman of United States Steel; and S. Bruce Smart, Jr., Chairman of The Continental Group. Frederick L. Webber, Executive Vice President of Edison Electric Institute, represents the electric utility industry.

Also contributing to the partnership are the many senior executives from business and industry who sit on the Conservancy's national and state chapter boards. Their active participation has helped to keep the organization lean and businesslike as it has grown and to foster efficiency through management by objective, effective annual and long-range (five-year) planning processes, etc. (The Conservancy's recently completed 1988 Plan is available to supporters and potential supporters.)

Executives from Arkansas Power & Light, Pennsylvania Power & Light, Montana-Dakota Utilities, Otter Tail Power, and several North Dakota cooperatives are among the many businesspeople serving on the boards of Conservancy chapters and leading grassroots fund-raising campaigns across the country.

Trading Up Corporate Assets

The Nature Conservancy offers business another opportunity through its "trade lands" program. Many corporations own real estate, developed or undeveloped, which is no longer serving a useful purpose for them and for which sale at an acceptable price, especially today, can be hard to achieve. When there is substantial appreciation in the property's value, managers often fail to consider the donation option.

By donating non-productive land to charity, a company can dispose of it quickly and easily and realize immediate tax savings for re-investment, while contributing to the community at the same time. In favorable circumstances, such a donation can be more rewarding in dollars and cents than an open market sale.

Donated real estate may be commercial, residential, industrial, urban, or rural. It may be land, buildings, or mineral rights. The Conservancy will then sell the donated property and apply the net proceeds to protecting natural areas.

In the past two years alone, 59 such real estate gifts have been made to the Conservancy, with a total estimated fair market value of $7 million. Among the properties donated by corporations have been a surplus oil storage site on Long Island, commercial property in Boston, a gas station in Washington State, two brownstones in midtown Manhattan, and a warehouse in Florida. Donors such as Gulf, Mobil, 3M, Kimberly-Clark, PPG Industries, and Chevron USA have participated, to the benefit of their corporate interests as well as conservation.

New Stakes

While the private sector historically has provided critical leadership in natural area preservation, the federal government has put up the lion's share of the dollars. More recently, however, the state of the economy and the resulting cuts in the federal budget have drastically reduced the land acquisition funds that federal and state conservation agencies depended on.

Without these resources, the pace of preservation has slowed perilously. For the most part, what little is left of our untouched natural heritage will be either protected as it is or converted to other uses in the next decade—perhaps 20 years at the most. If we are to pass on to our descendants even an approximate representation of the natural endowment that we hold in trust for them, private philanthropy will have to allocate significantly more of its resources than the token 1 percent it now provides for environmental needs.

Not long ago, Bruce Smart, Chairman and Chief Executive Officer of The Continental Group and member of the Conservancy's Board of Governors and Corporate Relations Committee, explained:

> When it comes to choosing between the economy and the environment, no respectable citizen, certainly no environmentalist or businessman, can safely continue to be blindly committed to a single side of these great issues. The Nature Conservancy has been uniquely successful in protecting habitat by enlisting corporate aid rather than denouncing corporate motives.
>
> No business can be successful in a world whose ecosystems have broken down. . . . Each of the earth's species contributes its activity and its genetic pool to the diversity, stability, and preservation of our ecosystem. Man depends totally on these species for the habitability of the planet. Once lost, a species cannot be replaced and its unknown future is lost with it.

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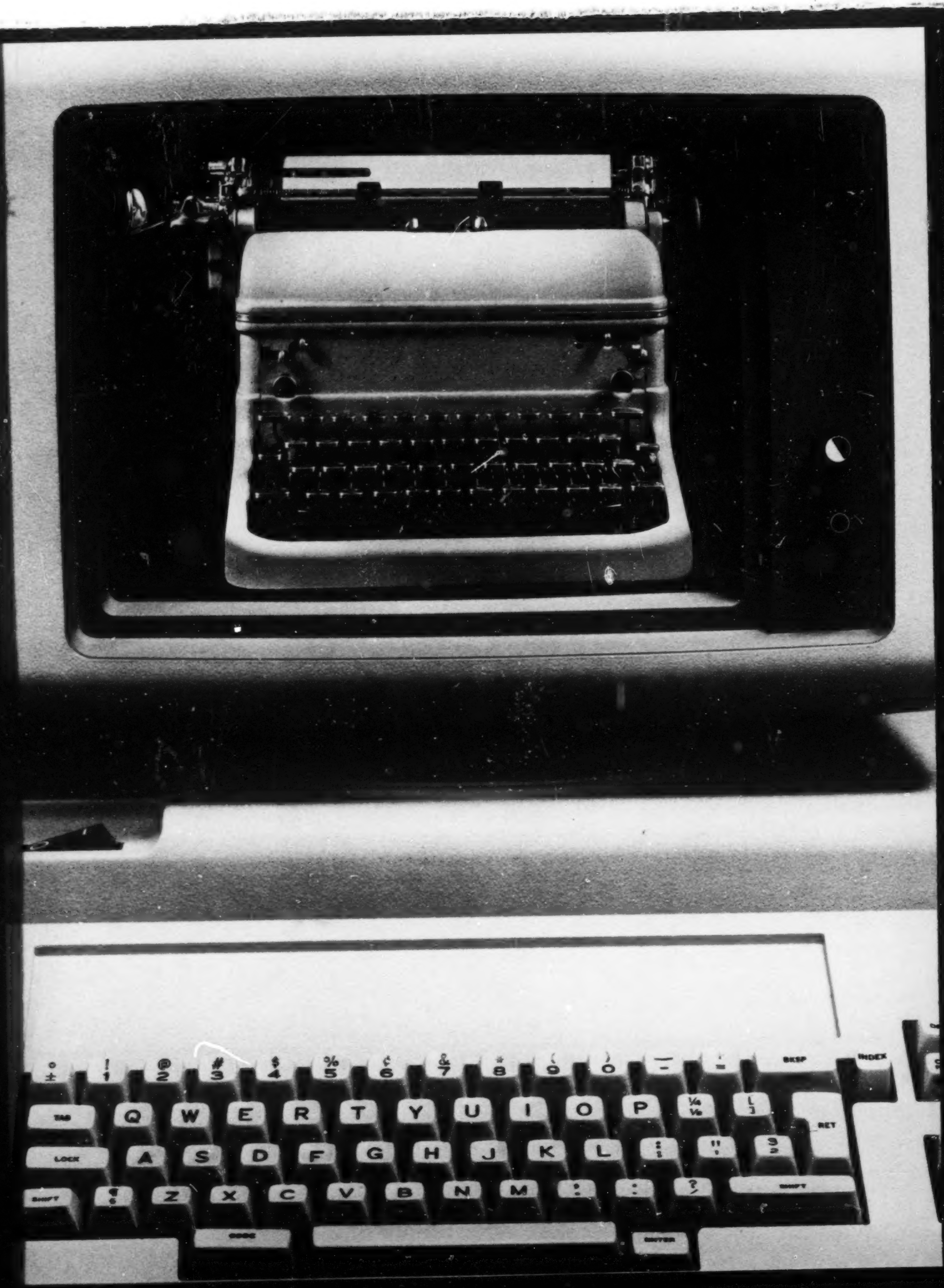
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The Changing Culture of Electric Utility Management

By Kenneth Haygood, Ph.D.

culture (kul'chər) *n*: the ideas, customs, skills, arts, etc. of a given people in a given period . . .

Long characterized by hierarchical organizational structures and traditional management practices well-adapted to a stable operating environment, electric utilities have had to adopt a more flexible management culture, explains management expert Kenneth Haygood. In this first article of a two-part series, he reviews how changes in the industry's operating environment during the 1970s created the need for a new management culture. In his second article, he will enumerate specific steps the electric utility industry could take to help ensure its management culture is as effective as possible throughout the 1980s.

In the decades in which the industry grew up and throughout the 1950s and the 1960s, most electric utilities were effectively managed. They met reasonable criteria of sales and earnings growth, return on capital, reliable dividend payments, and ease of raising investment capital. They also met the needs of their growing markets with economically produced and reliably delivered electricity. Most customers were satisfied, and electric utility regulators were generally supportive.

There was a good "fit" between management practices and the industry's operating environment.[1] Managers were thoughtful and deliberately took a low-risk approach to management because the future seemed relatively predictable. They tended to be technically and financially oriented, which was appropriate since the problems they faced required expertise in that range of issues. Top managements' outlooks, attitudes, and expertise fit well with the prevailing business conditions.

Then, in the 1970s, the management of many electric utilities *seemed* to lose effectiveness. Fuel costs soared. Supplies were interrupted. Interest groups organized to fight rising electricity prices. Government regulations delayed construction. Costs rose with inflation, and high interest rates added to the difficulties. Bond ratings fell. Regulators became skeptical about rate increases and resisted approving returns sufficient to attract capital for investment. Dividend increases were threatened.

Actually, utility managers could not have controlled all these events even if they could have predicted them. Utility managers were caught in the crunch of a changing operating environment.

Still, their management practices, derived from the experiences of earlier years, did not fit well with the challenges of the new environment. And, even though the managers were making many changes to adapt their practices to fit the changing conditions, they were a convenient target for dissatisfied ratepayers, stockholders, and regulators.

Now, what are the prospects for the decades to come? The electric utility industry will continue to make difficult choices in circumstances different from those of the past and present. Examples abound:

- How should the industry commit its resources for future energy development?
- Should the industry seek to ensure future reliability at all costs or take the approach of "capital minimization"?[2]
- Should the industry focus its efforts on governmental and regulatory affairs to achieve a more favorable climate for its regulated activities, or should it shift its focus to developing businesses in non-regulated areas?
- Should utilities get out of electricity generation and simply become distributors of power, or should they

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continue to invest in the development of resources that enable them to produce electricity?

To choose wisely in the 1980s, electric utility managers will need to continue sharpening their ability to perceive the signals of approaching new conditions. They will need even greater insight into the nature and implications of the changes, new concepts to help them understand the environment, and an increased willingness to act, even if the outcome of their actions is not entirely predictable.

In short, to adapt to tomorrow's conditions, top management must continue to increase its ability to be genuinely flexible.

> The kind of flexibility required of today's and probably tomorrow's management is a gut-level, basic change in insight, concept, and perception. It is the antithesis of blind dogmatism with its unyielding, absolutist, righteous positions on the one hand and of weak, unctuous agreeableness on the other. Flexibility takes such inner strength and certainty as to one's directions and goals that necessary compromises or modifications in policy and practice are neither threats nor defeats. True flexibility expresses one's ability to change his mind because he's learned something and has seen a better way of implementing a principle.[3]

To choose wisely in the 1980s, electric utility managers will need to continue sharpening their ability to perceive the signals of approaching new conditions.

How can utility managers best ensure they maintain the flexibility required to adapt their practices to fit changing conditions? The answer may lie in managing the "culture" of their companies.

Every company has a culture, a way of doing things. These cultures are usually determined by the company's founders or top leaders. The culture is based on the values which hold the company together and shape its management practices.

Management researchers Terrence Deal and Allen Kennedy studied company cultures and found that they can be categorized into four types according to the degree of risk that management must take and the rapidity with which the results of management's actions are known:

- *Tough Guy Macho,* in which there is high risk and quick feedback of results, e.g., police departments, sports organizations, television stations, oil drilling companies;
- *Bet Your Company,* with high risk but slow feedback of results, e.g., capital goods companies, oil companies, mining companies;
- *Work Hard/Play Hard,* with low risk and quick feedback of results, e.g., real estate sales, retail stores, restaurants;
- *Bureaucratic/Process,* with low risk and slow feedback of results, e.g., banks, insurance companies, many government agencies.[4]

These cultures are adaptive to their environments. All have strengths and weaknesses, with behavior patterns characteristic of their types of organization. For example, in the bet-your-company culture, the focus is on the future, and experience is valued as one aid to making good long-range decisions. In the bureaucratic/process culture, there is great attention to detail, procedure, hierarchy, and form, and changes are made slowly.

Although Deal and Kennedy categorize utilities as having a bureaucratic/process culture, utilities have not fit that cultural pattern since the 1960s. The more appropriate cultural description for electric utilities, given their recent operating environment, is the bet-your-company culture, in which there is very high risk but slow feedback of results. For example, if an electric utility commits itself to a long-term conversion from oil to coal, the outcome of the decision will not be known for years, and intervening events over which the company has no control may cause the decision to turn out to be a great success or a disastrous mistake. Still, electric companies have had to make such risky decisions, and they will have to in the future as well.

In fact, the choices are not going to get easier. Future decisions will require even greater sophistication and higher levels of managerial self-confidence and courage. Therefore, one of the main tasks for the utility executive today is to manage the culture of his company to ensure it continues to foster the development of adaptive management practices—practices that maximize the likelihood of success and minimize the chances of failure. Management must rid itself of non-adaptive practices such as:

- *Heavy reliance on past experience when dealing with new challenges,* which causes attitudes to become fixed, narrows perceptions, and discourages new ideas.

- *Promotion primarily from within the company and the industry,* which encourages employees to play it safe so seniority will carry them to the top. It promotes rigid thinking, reduces willingness to take risks, and encourages managers to protect each other. As a result, poor practices and errors in judgment are sometimes covered up.
- *A compensation system not geared to reward talent,* which generally emphasizes security and results in a "don't-rock-the-boat" approach by employees.

Instead, management must continue to implement practices that support adaptive cultures:

- *An ongoing strategic planning system* that provides up-to-date information about trends, problems, and opportunities. It enables the company to develop alternatives for action, to select options, and to test them before they are put into practice. A good system also allows the company to track its progress as it pursues its course of action.
- *A manpower planning and development system* that assures the company of a continuous flow of management talent from both within and outside the company. When linked to long- and short-term strategic business plans, the manpower plan can provide talent for today's and tomorrow's needs.
- *A strong compensation plan* that encourages excellence, rewards merit, and helps open avenues for capable people to enter the electric utility industry. It encourages new ideas and infuses the company with insights and experience not previously available to it.
- *Comprehensive and well-integrated involvement with local, state, national, and international governmental affairs,* involvement which will grow increasingly important as the complexity of the global economy and its effects on local affairs increases.
- *Adaptive organizational structures* that allow work by small groups of people who have very clear objectives to be integrated with the work of other such units so that a coordinated approach to achieving the company's objectives can be maintained by top management.[5]

Although some of these management practices have been adopted by individual companies, they have not yet been refined and developed to suit the industry's particular needs. To encourage further adoption of effective practices the electric utility industry should consider gathering information about industry-wide management practices in order to:

- Identify which practices are most successful in the particular conditions under which utilities operate;
- Inform utilities' top management of those practices that best fit their corporate culture and contribute most to coping with the changing demands the industry faces;
- Develop programs to help companies implement new management practices that will be useful in their particular circumstances;
- Provide an ongoing means to evaluate the effectiveness of new management practices adopted by electric utility companies and to disseminate the information to interested companies.

Electric utility companies have taken great strides to meet the enormous challenges thrust upon them. But further challenges lie ahead that will require the most useful concepts and powerful management tools available. Effective management practices adapted to the special needs of electric utility companies can play a significant role in shaping a strong company culture capable of successfully meeting present and future challenges.

Effective management practices adapted to the special needs of electric utility companies can play a significant role in shaping a strong company culture capable of successfully meeting present and future challenges.

Notes

1. Rohrer, Hibler & Replogle, Inc., *The Managerial Challenge* (New York: Signet, 1981), Chapter 2.
2. Peter Navarro, "Our Stake in the Electric Utilities' Dilemma," *Harvard Business Review,* May-June 1982, pp. 87ff.
3. Rohrer, p. 246.
4. Terrence E. Deal and Allen A. Kennedy, *Corporate Cultures* (Reading: Addison Wesley, 1982), Part 1.
5. Thomas J. Peters and Robert H. Waterman, Jr., *In Search of Excellence* (New York: Harper and Row, 1982), Chapter 7. The authors report that successful companies often are organized into small profit centers in which competition and risk taking are encouraged and that this combination of practices results in innovation and new ideas better suited to new conditions and challenges.

Strategic Planning: Getting the Job Done

By Carl F. Jaedicke

Formulating and pursuing corporate objectives can be accomplished through a particular process of analysis and action

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Because formal strategic planning is a relatively new concept for most electric utilities, a large amount of uncertainty currently exists about how to accomplish it. For example,

- What are the constitutent steps of the strategic planning process, and how are they related?
- What are strategies?
- Who is responsible for the work of strategic planning; that is, how are organizational elements allocated to the process?
- How does strategic planning relate to the other planning activities in an electric utility?

Although literature on strategic planning theory abounds, articles that explain how to put that theory into practice—that give practical answers to practical questions—are not always easy to find. It is my intent here to help remedy that situation by relating some of the basic tenets of strategic planning theory to the specific needs of electric utilities and, more specifically, by answering the questions posed above.[1]

The Strategic Planning Process

Strategic planning is the process and activities by which a firm determines its mission and objectives and selects a plan of action to pursue them. The process may be summarized in six steps (see Figure 1), the first of which is the *development of the firm's strategic profile.* The strategic profile captures a firm's unique identity as defined by its corporate mission and objectives, its competitive posture, and its personal culture. It is a key driver of the strategic planning process, providing guidance for all other steps.

Although the first elements of the profile, corporate mission and objectives, are familiar topics, competitive posture and corporate culture both merit further explanation.

To assess its competitive posture, a firm must identify its competitive advantage and position. Competitive advantage is the characteristic of a firm's product offer that makes the firm competitive in the marketplace. For example, cleanliness and ease of use are characteristics of electricity that give it a competitive advantage *vis-a-vis* other fuels.

Competitive position is principally defined by market share. For electric utilities, competition comes from other energy sources, primarily coal, oil, and gas, and from customer-owned generation. Conservation also competes because it shrinks the total market demand for electricity. In analyzing its competitive position, the firm also should evaluate major changes and emerging trends in market share among competing firms. For example, the rise in energy prices that led to the demise of traditional utility marketing programs has eased the entry of new competitors, such as cogeneration and solar power. As utilities respond to this development, analyses of competitive advantage and position will become increasingly important.

Corporate culture, the fourth ingredient in a strategic profile, concerns the unique value system of a firm. Similar to a country or region, a corporation develops values that become ingrained in its activities, opinions, and actions. For example, most electric utilities place a high premium on service reliability. Through word and example, employees reinforce these values over a period of many years. The cultural values themselves are not inherently good or bad. They are strengths or weaknesses depending on the require-

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The strategic plan . . . documents a set of strategies that deals consistently with the key issues and facilitates the pursuit of the corporate mission and objectives.

ments of the issue at hand. Together, they characterize a firm's corporate culture. That culture may be modified, but it is difficult to modify it in the short term.

A firm's culture generally is identified by reviewing past actions. Virtually all corporate documents, external and internal, contain cultural information. Some values are stated explicitly, and others appear "between the lines." The cultural analysis may be performed internally, but there are obvious advantages to retaining an outside consultant for this activity.[2]

The second step in the strategic planning process is the *analysis of the external environment.* The object of this analysis is to identify external opportunities and threats that may significantly affect the pursuit of the corporate mission and objectives. To accomplish this task, the environment is generally subdivided into several dimensions. Typical dimensions are economic, competitive, market, technological, and sociopolitical. For instance, one utility might identify cogeneration as an opportunity in the technological dimension. Alternatively, another utility might classify it as a threat in the competitive dimension.

Obviously, analysis of the external environment entails making certain quantitative and qualitative assumptions about future environmental conditions. A long-term sales forecast is an example of a quantitative assumption, and projections of social or regulatory trends are examples of qualitative assumptions.

The *analysis of internal resources,* the third step in the strategic planning process, is conducted to identify the firm's internal strengths and weaknesses. Usually, they are developed in categories such as finance, operations, and management. For example, to be in a strong cash position is a financial strength; to be dependent on a single supplier for a key product input, such as coal, might be an operational weakness. Like opportunities and threats, strengths and weaknesses are relative to the directions and values identified in the strategic profile. And, like the analysis of the external environment, the analysis of internal resources also requires making some assumptions. A typical resource assumption, for instance, details the current generation expansion plan. Sometimes, as a byproduct of this analysis, additional external opportunities and threats are identified. Strengths often foreshadow opportunities, and weaknesses may be related to threats in the business environment.

The fourth step of the strategic planning process involves the *determination of key issues.* The opportunities and threats identified in step two must be ranked according to their projected impact on the pursuit of the corporate mission and objectives. The strategic profile, external and internal assumptions, and internal strengths and weaknesses provide a framework for this evaluation. High-ranking opportunities and threats are designated as key issues and become the subject of detailed individual analysis.

Once the key issues facing the firm have been determined, strategies to address them must be identified and evaluated. This fifth step, *strategy formulation and evaluation,* results in recommended strategies that capitalize on opportunities and minimize threats. On balance, these strategies must be consistent with the strategic profile, with the resources of the firm, and with what is possible in the external environment.

Despite the common framework from which these recommended strategies emerge, the key issues, and the varied requirements of these issues, will inevitably produce conflicting strategies. Hence the need for the final step in the strategic planning process—the *integration of recommended strategies.* Integration of strategies is a complex task, requiring the trading off of objectives, issues, timing, and resources. As part of this integration, strategies are categorized to assess the balance of the overall strategic plan. Typically, categories are related to corporate objectives, environmental dimensions, or major organizational units. The strategic plan, the end result of this six-step process, documents a set of strategies that deals consistently with the key issues and facilitates the pursuit of the corporate mission and objectives.

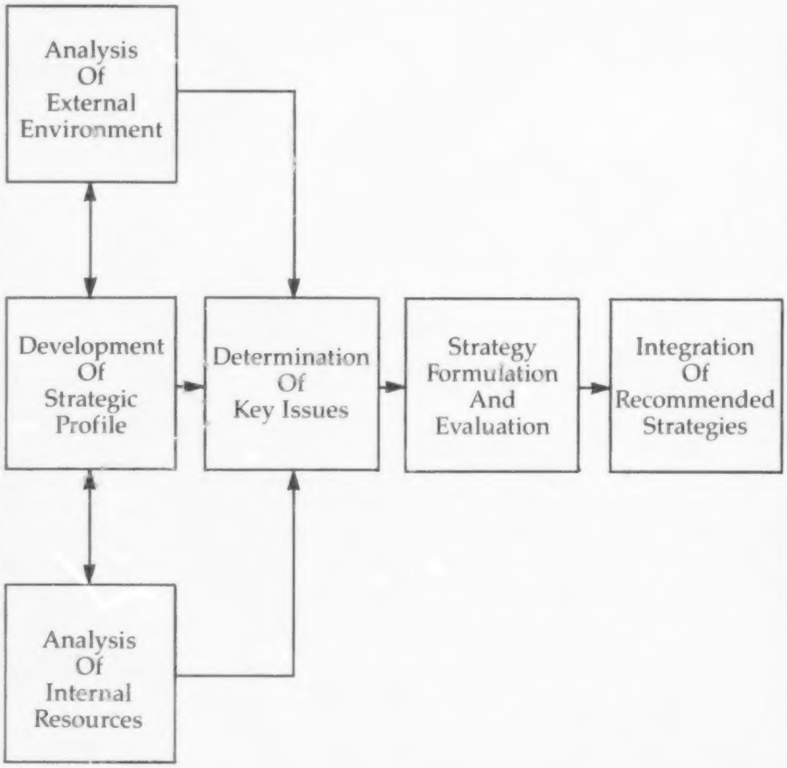
What Are Strategies?

Corporate planning experts generally concur that the output of a strategic planning process is corporate strategy. At that point, however, most agreement ends. There is a wide variety of opinion about exactly what constitutes a strategy. Two of the most frequent points of confusion are *intent* and *form.* The issue of intent centers around whether strategies address "*what* the firm should be" or "*how* it plans to get there." In other words, are strategies ends in themselves or means to an end? Regarding form, some theorists argue that strategies are broad corporate guidelines, while others argue that strategies are specific solutions to key issues.

The question of intent may be conveniently discussed in terms of the strategic planning process. "What the firm should be" is addressed in the statement of corporate mission and objectives contained in the strategic profile developed in step one. The question of "how to get there" is resolved further downstream in step five when strategies to deal with key issues are formulated. Thus, both concepts of a "strategy" are legitimate in the strategic planning process. The confusion appears to be related to the point of reference and can be cleared up if the two concepts are distinguished by different terminology.

The question of form is generally raised with respect to the downstream strategies of steps five and six. Are they broad corporate directives or specific solutions? The fact is, they may be either. Strategies are developed in various levels of detail depending on the particular issue being confronted. If the issue is substantially related to the responsibilities of existing organizational units, the corporate strategies addressing it tend to be general, in the form of policy guidance. Other issues, due to their importance or uniqueness, may be subject to much more specific strategy specification.

Figure 1. Strategic Planning Process


Analysis Of External Environment
Development Of Strategic Profile
Determination Of Key Issues
Strategy Formulation And Evaluation
Integration Of Recommended Strategies
Analysis Of Internal Resources

The Allocation of Organizational Elements

A third area of uncertainty involves the allocation of human resources to the strategic planning process. Is strategic planning the exclusive purview of the executive group? How much "power" should the strategic planning staff wield? What about line managers; how are they involved?

The strategic positioning of the firm is ultimately a prime responsibility of corporate executives. Formal strategic planning provides a framework in which they can assume and exercise this responsibility. Their principal role is to review and approve various strategic planning outputs. These functions should not be interpreted as a minimal level of involvement. Management must actively participate in these tasks if the strategic plan is in fact to establish a course of action for the firm. Limited or insincere management involvement will send a clear signal to the rest of the organization and inevitably will result in a lifeless process with insignificant outputs.

Likewise, the strategic planning staff must make a unique contribution to the process. Although they may initiate much of the analysis, their most critical responsibility is the design and implementation of the process. Professional planners must see themselves as facilitators rather than formulators of the corporate strategic plan.

Finally, line managers do have a role to play. In successful strategic planning, line managers must be involved in many of the detailed activities. Generally, they undertake these responsibilities as members of planning task forces. Their expertise and realistic perspective balance the generalist perspectives of the planning staff.

Table 1 illustrates a *sample* mapping of these three organizational elements to the procedural steps involved in strategic planning. It is offered as an example, not as a theory. Each utility is unique, and the allocation of these tasks varies with the culture and needs of individual firms. In general, the strategic planning staff members or task forces originate work packages. Almost all packages are reviewed by the executive planning group. The intensity of review varies according to the particular topic. Executive approval is required only for outputs that have corporate significance beyond the needs of the formal planning process.

In sum, a participatory approach to strategic planning is necessary. Executives, planners, and line managers each have key responsibilities. The diversity of expertise and experience represented by the three organizational elements increases the likelihood that strategies formulated will be innovative and creative. Moreover, with the participatory approach, support for new directions will be developed on a broad basis. This support will prove invaluable to the subsequent task of strategy implementation.[3]

Table 1. Allocation of Organizational Elements to the Strategic Planning Process

Planning Process Step	Analysis	Review	Approval
1. Development of Strategic Profile			
a. Mission	Strategic Planning Staff	Executive Planning Group	Executive Planning Group
b. Objectives	Strategic Planning Staff	Executive Planning Group	Executive Planning Group
c. Competitive Posture	Strategic Planning Staff	Executive Planning Group	—
d. Corporate Culture	Outside Consultant	Executive Planning Group	—
2. Analysis of External Environment			
a. Opportunities and Threats	Strategic Planning Task Forces	Executive Planning Group	—
b. External Assumptions	Strategic Planning Task Forces	Executive Planning Group	Executive Planning Group
3. Analysis of Internal Resources			
a. Strengths and Weaknesses	Strategic Planning Staff	Executive Planning Group	—
b. Internal Assumptions	Strategic Planning Task Forces	Executive Planning Group	Executive Planning Group
4. Determination of Key Issues	Strategic Planning Task Forces	Executive Planning Group	—
5. Strategy Formulation and Evaluation	Strategic Planning Task Forces	—	—
6. Integration of Recommended Strategies	Strategic Planning Staff/ Strategic Planning Task Forces	Executive Planning Group	Executive Planning Group

The Relationship of Strategic Planning to Other Planning Activities

Strategic planning is principally intended to address issues with broad corporate impact. It is one element of a larger process called corporate planning. This process is composed of four activities: strategic planning, functional planning, operational planning, and budgeting. Functional planning is the first level of planning that occurs within major organizational units of the firm. In electric utilities, functional areas typically correspond to vice presidential responsibilities. For example, fuel supply and energy distribution could be considered functional areas. Generally, a functional area comprises a number of departments. Operational planning then takes place at the departmental level. Budgeting, the fourth corporate planning activity, involves allocating the corporate resources required to implement the operational, functional, and strategic plans.

Though distinct in concept, the four activities are interdependent within the corporate planning process. Typically, the process progresses from strategic planning to budgeting. As discussed earlier, corporate strategies are developed in various levels of detail. Some provide guidance and policy direction for a variety of functional and operational plans. Others indicate specific programs that must be designed and budgeted by functional and operational areas. As an example, a utility might develop a corporate strategy to increase area development. This strategy would affect planning in a variety of functional areas including customer services, rates, and energy supply. New marketing programs then would be necessary at the departmental or operational level, and a reallocation of resources would be required to support the new level of emphasis. Naturally, there is a substantial amount of interaction at all stages of the process.

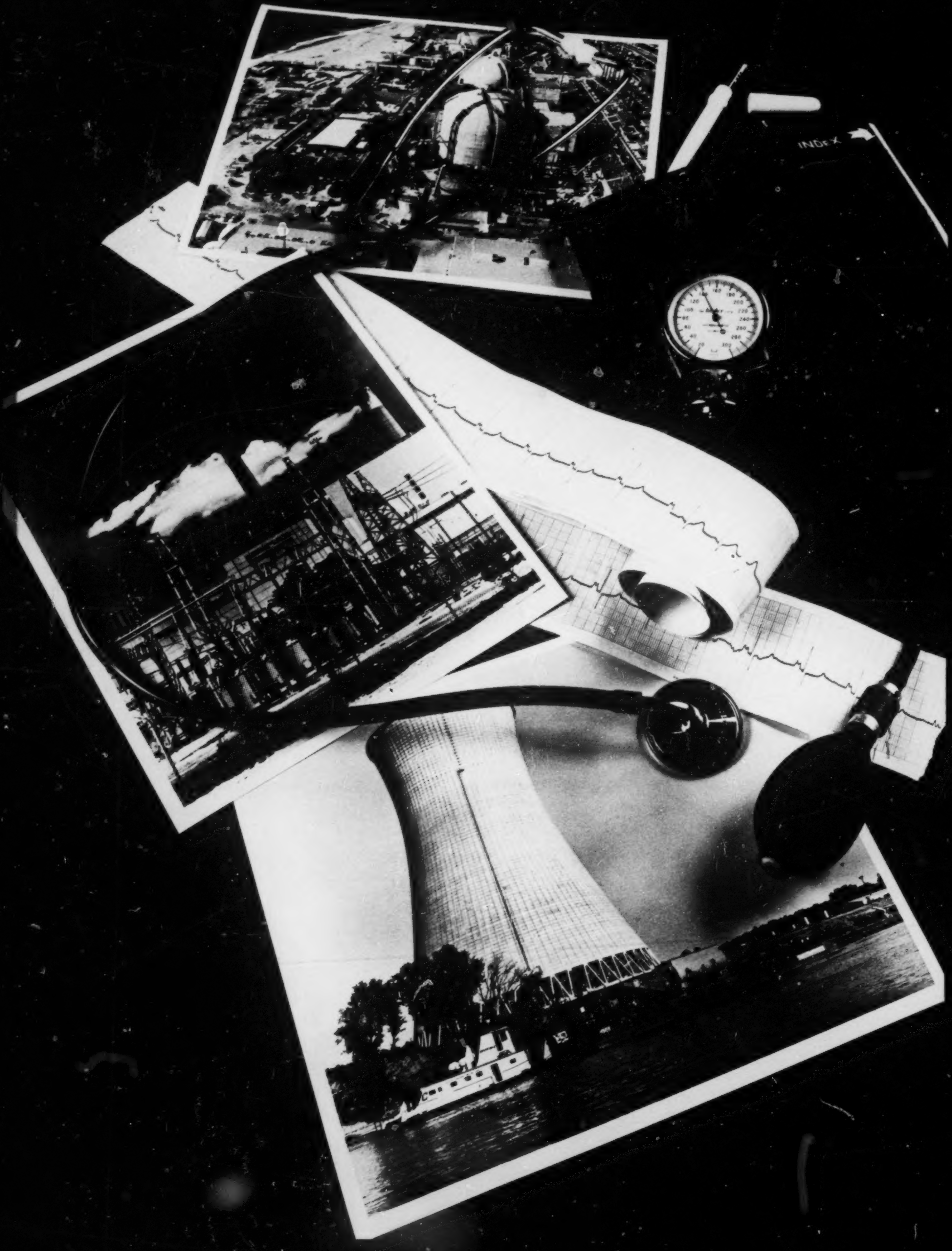
Ultimately, the plans are implemented. The success of the corporate planning process can then be measured by corporate performance. Admittedly, the correlation is complex. Formal corporate planning, however, provides a strong framework for such an evaluation. Were the corporate strategies inadequate for the issues? Did unforeseen events sabotage otherwise sound strategies? Did functional plans fail to capture the intent of strategic guidelines? Was implementation faulty? The answers to these questions provide input for the next cycle of the corporate planning process.

In sum, strategic planning is one element of a comprehensive corporate planning process. To be successful, it must be related to the other planning activities that a firm undertakes. Electric utilities now in the process of establishing a strategic planning capability should recognize this fact. If strategic planning is purposely or inadvertently disconnected from functional planning, operational planning, and budgeting, its contribution to the firm will be seriously compromised.[4]

If strategic planning is purposely or inadvertently disconnected from functional planning, operational planning, and budgeting, its contribution to the firm will be seriously compromised.

Notes

1. Although the ideas expressed here have originated from my experiences at Consumers Power Company, they are not necessarily representative of the policies or programs of my firm.
2. For an excellent introduction to corporate culture, see "Corporate Culture—The Hard To Change Values That Spell Success or Failure," *Business Week*, October 27, 1980, p.148–160.
3. I have discussed organizational considerations in greater detail in a previous article. See "Strategic Planning: A View From the Bottom Up," *Public Utilities Fortnightly*, December 3, 1981, p.52–55.
4. For an interesting comment on the ramifications of disconnection, see "Management Is Drowning in Numbers," by Thomas H. Naylor, *Business Week*, April 6, 1981, p.14–16.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How Healthy Are the Utilities?

By James N. Bumpus

Utility managements shift from business as usual to thinking the unthinkable

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The decisions facing utility managements around the country at this time seem to me more formidable than ever. One reason for this is that, for the first time, there are some alternatives that not so long ago would have been instantly relegated to the realm of the unthinkable. For instance:

- **What if** the load doesn't grow or, more horribly, what if it declines?
- **What if** the commission won't let us put the new plant, which is more than half the company's assets, in rate base right away?
- **What if** some goofball technology comes along and we can no longer sell central station power competitively?
- **What if** investors won't provide capital?
- **What if** regulators won't allow a true economic profit?
- **What if** the generating side of the business is deregulated?
- **What if** we go into some other business or businesses?
- **What if** we go out of the utility business?

These and similar questions are in fact being asked by the managements of electric utilities in the United States. To be sure, many decisions are still being based on "business as usual" assumptions, but as more and more of those assumptions are called into doubt, the enormity of the risk facing this industry begins to take shape.

I contend that we are faced with nothing less than the risk that our industry will not survive the next 30 years.

Understand that this is not a forecast. Forecasting is what economists do. Making decisions in a risky environment is what managers do. The central change in our business arising out of recent experiences is that we now recognize that the electric utility business as we know it may not survive.

This change poses two questions: First, just how risky is the electric utility business; are we truly dealing with the risk of business extinction? And second, what, if anything, should we be doing to protect ourselves?

To gain a better understanding of the risks the utilities face, let's first look at some of the financial background. I can do this against a backdrop of optimism—or what seems to be optimism—emanating from a part of the investment community: The securities analysts and the investment institutions.

For the past year or so, we've seen a growing body of professional investment opinion turn positive toward the electric utilities. One by one, the brokerage analysts have sent forth favorable reports chronicling the improved financial condition of the industry, the so-called "fundamentals." These analysts have cited regulatory improvements, including higher allowed and earned returns on equity; reduced construction programs in the wake of slower sales growth, and completion of committed power plants; impressive cost-control programs; and lower expectations for inflation resulting in lower interest rates and higher stock prices.

As I said, the analysts have been cautiously climbing aboard this bandwagon for about a year now, and it's interesting to note that in spite of *their* optimism, investors have only recently become sufficiently impressed to change slightly the terms on which they will purchase the stock. To be sure, utility stock prices had an upward trajectory through 1981 and 1982. But it is worth noting that the dividend yield—that is, the annual dividend rate divided by the market price—generally

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remained within a range of 11½ to 12½ percent during most of the period. Only recently has the yield declined materially because the market as a whole has responded to the prospect for substantially lower interest rates.

This pattern suggests to me that the market is still interested in utility stocks primarily for their dividends. As dividends grow, prices will rise in proportion to the increase; but there's little evidence that investors—as contrasted with analysts, whose job it is to seduce investors into following their recommendations—have bought the argument that the better fundamentals will bring about significantly stronger long-term earnings growth and price appreciation.

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It can be argued that the financial institutions have made massive commitments to the industry in recent months, and indeed they have. The question is, why? Does it have much to do with the attractiveness of the industry? I'm suspicious for two reasons. One is that, under the new rules of the SEC, common stocks can be sold in large amounts and on very short notice to institutional buyers. Thus there has been enormous motivation—provided by the utilities themselves as well as the investment banking fraternity—to take advantage of so-called "windows." Windows are those occasional opportunities provided to take advantage of a relatively high selling price or a large investor appetite. The high price pane of the window has been opened by a market that is suddenly enthusiastic about the recession-induced prospect for lower long and short-term interest rates.

The other pane of the window, the institutional appetite, has been opened by the reality of much lower short-term interest rates. During most of 1982, many institutions have been avoiding new commitments to either stocks or bonds. As a consequence, they had built up very large positions in short-term cash equivalent investments. That was fine as long as short-term interest rates stayed high, but when those rates started to dive early last fall, there was heavy motivation for institutional portfolio managers to move into more permanent investments. The utilities, with their insatiable needs for capital, were ready and willing to trade their paper for the institutions' cash.

The net of all this is an improvement of approximately 10 to 15 percent in utility stock prices, virtually all of which has taken place since August 1982. Interestingly enough, long-term interest rates are down about 15 to 20 percent from July levels.

In short, we have seen a significant, but not overwhelming reduction in long-term interest rates accompanied by an opposite reaction in utility stock prices. Big surprise: utility stocks still trade as a function of interest rates. So if you want to know the future course of utility stock prices, simply choose your favorite prognosticator of interest rates and do exactly what he says. Or its opposite. Your likelihood of success is equal with either approach.

But aren't things really better? Of course they are. Cheaper capital is always better, but we must keep proper perspective. It's good to rejoice that utilities can raise debt capital at less than 13 percent now versus 16½ percent not so long ago. But our average cost of existing debt is more like nine percent and it is on that embedded cost that our rates are based.

It's also good that utility stock prices are up, but again the perspective is revealing: At the end of 1982 there were 29 of 106 utilities in Kidder-Peabody's universe whose stock sold over book value. Not so long ago, there were 2. For the 27 newcomers to the stratosphere, it's great, because now they can—theoretically and if they are fast on their feet— sell more stock without diluting the assets and earnings of the existing stockholders. But on average, the industry sells for 95 percent of book value now and there are 77 of the 106 who cannot raise new equity capital without dilution. And that dilution, combined with relatively high interest rates, means that continued bad news is in store for utility customers and investors.

So much for the great bull market of 1982-83—so far. What would it take to get the industry, on average, to book value? A 10 percent price improvement, and that would still leave half of us in the soup. Assuming a perfect correlation of stock prices and long-term interest rates, 10 percent improvement would put such rates at the 10½ to 11 percent level from 13 percent or so today.

Your assessment of the probability of that happening is as good as mine, but I'm not holding my breath.

We've seen that the stock market is treating the utilities better, but not well. One question is: Do we deserve better? How attractive are we as an investment? Is the market just slow to recognize our charms or are we in an increasingly risky business?

Let's take a look at basic profitability expressed in its purest terms: The rate of return on common equity capital. Here both regulators and utilities have much of which to be proud. Allowed returns on equity have grown from 1974's 12.5 percent to an average of 15.8 percent last year. The trend is still up for the time being. Consider though, how those returns came about. In large measure they were allowed in response to the persistence of very high interest rates and to the fact that utility credit ratings were dropping like stones. Construction programs were and are being curtailed and, during the late 1970s, serious concerns about future power supply were heard from more than one regulatory bench. In short, regulators were scared, and they responded by increasing the allowed returns dramatically from their earlier levels.

Interestingly enough, even though allowed returns on equity have increased, interest rates have been higher still. Since 1979, 30-year single A utility bonds have generally provided a higher average return than the commissions authorized on equity. Adding insult to injury, the utilities—while increasing the level of their realized profits—were actually earning far below the authorized levels. In fact, the margin between the authorized and the achieved rate of return has steadily widened since 1974 when it was 1.8 percent to 1981 when it was 2.6 percent. In 1982, the margin has narrowed a bit—to 2.1 percent. It is encouraging indeed to see that the electric utility industry has increased its average rate of return on equity from 11.4 percent in 1980 to 13.75 percent by September 1982.

But what of the three-fourths of the industry who even now cannot sell stock above book value? When a stock sells below book value it indicates that investors consider its earnings to be less than the cost of capital. The simple truth is that electric utility rates do not cover the cost of making electricity, and have not covered those costs consistently at any time in the last 10 years. Until the utility stocks trade over book value *most* of the time, permitting substantial new sales at premiums instead of discounts to book value, one of two circumstances will prevail. Either the utilities will: One, continue to finance with sales below book value until investors revolt from seeing their earnings, dividends, and market prices erode; or two, refuse to construct new facilities when they cannot be financed without diluting equity. Presently we're seeing some of both.

Last year, 64 utilities sold 85 issues of common stock publicly, and 78 of those sales produced net proceeds of less than their book value. So even if the utilities can sustain the same rate of return after the sale—which would require a rate increase—the earnings and book value per share will be reduced. For many of us, this has meant little or no increase in either earnings or book value during the last eight to ten years. When inflation is taken into account, real utility profits have declined for more than a decade.

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But utilities are also reducing their construction programs and, thereby, reducing the need to sell new stock. Some utilities have announced specific policies designed to reduce or even eliminate the need for more dilution. Our own company, for example, has said that it will commence no new power plant construction until such time as it can finance the plant to completion *without* selling substantial amounts of stock below book value.

Such a policy is not easy to implement, particularly for a utility whose loads are growing fairly rapidly. The key—and this requires the cooperation of regulators and management—is to achieve a strong enough financial condition to make the construction program independent of future regulatory adversity or financial market disarray. It would seem to me that such policies

The power plants coming into service now were begun at a time when it was forecast that growth in electric demand would be much more rapid than it is now.

will set some natural limits on the magnitude of construction commitments.

The clearest indication of the fact that these natural limits are real and are being experienced is the nuclear power industry. No need to tell you the whole gory nuclear energy financial story. It is enough to say that no new nuclear units have been ordered since 1978 and more than a score have been canceled since August of 1981. The ultimate recovery of sunk costs is not yet assured in most cases. The delays and uncertainties of nuclear regulation have ballooned severalfold the projected costs of these plants—to the point where their basic economics are threatened. Capital costs of more than $3,000 per kilowatt of capacity are no longer rare for those nuclear plants scheduled for commercial operation in the next few years. Nor is it rare for a nuclear plant's cost to represent half—and occasionally much more than half—of a company's total capitalization. When half of your investment is in an asset that may not earn its cost of capital, is it any wonder that investors are not enthusiastic about the stock?

Why wouldn't the asset earn its cost of capital? There are several ways that could happen and some of them are happening right now:

1. Regulators can contribute by authorizing returns lower than the cost of capital. Such is the case in most jurisdictions today as it has been for many years. Does anyone here expect commissions to maintain high returns on equity as interest rates go down?
2. Utilities can contribute by earning less than the authorized rate of return. As discussed earlier, this remains a serious problem for most of the industry. Only fully forecast test periods coupled with ultra severe cost control can cure this.
3. Regulators can balk at the rate increases necessary to place a hugely expensive plant into rate base, and refuse or delay such treatment.

The exclusion of a plant from the rate base, while usually motivated by consumer-oriented financial concerns, may be even more easily rationalized if the argument could be made that the plant is not needed. Never mind how convinced we were of its necessity when we started to build it. Approximately one-fourth of the largest investor-owned utilities reported 1981 reserve margins in excess of 35 percent. At least 12 such companies, with reserve margins ranging up to 50 percent or more also have substantial additional capacity under construction. How will those new plants be treated by the regulators?

The status of the industry's reserve margins raises other questions in the minds of investors. As you are all probably aware, load projections have been coming down rapidly as conservation and load management technology assert their impact. The power plants coming into service now were begun at a time when it was forecast that growth in electric demand would be much more rapid than it is now. Thus the industry finds itself at the end of 1982 with a 27 percent reserve; not excessive on average, but with all the new capacity still in the construction pipeline, it's likely that the margin will continue to rise for several more years. We've already discussed the potential that large reserve margins create for adverse regulatory treatment. But what about the underlying load growth itself? What's happening to the economic growth of our industry and what does that mean for investors?

From the end of World War II until fairly recently, we experienced a rate of sales growth that, for most of that period, made our stocks the darlings of Wall Street. The economies of scale and technological improvements that we implemented in the '50s and '60s made us that rarest and most beautiful of all economic animals, a declining cost industry. In those days we were the financial equivalent of today's computer industry: the more we made and sold, the cheaper our product became.

With the advent in the late '60s of inflation and environmental protection coupled with the maturation of our basic technology, a triple blow was struck to our enviable declining cost position.

1. Inflation took the cost of one of our basic product ingredients, capital, from less than 3 percent in the late '40s to nearly 20 percent at times in the early '80s. Not only do we have to pay vastly more for much larger amounts of new money, but the cheap debt we sold 30 years ago has

to be paid off now by the sale of bonds bearing interest at today's high rates.

2. The nation decided, properly in my view, to commit itself to a goal of keeping the benefits of the industrial society while cleaning up its harmful residue. The problem is that we may have exceeded the point where the benefits outweigh the costs. When we consider that current pollution control requirements can easily consume 20 percent of the cost of a power plant and 10 to 15 percent of its electric generating capacity, one has to wonder how clean we can get without pricing the industry out of its market.
3. The days when each new, ever larger, generating unit came in at a heat rate lower and operated more reliably than its predecessor have gone. Electric generating technology has become mature. And so the cost of electricity, due to inflation and pollution control, continues to rise unimpeded by major technical innovation.

What does all this mean for the status of our companies as "monopolies," natural or otherwise? We all know, or are learning, that our customers of all classes are finding substitutes for our product. They're substituting:

- The capital investment in thermal envelopes to reduce our heating loads;
- Their investment and inconvenience by adopting load management strategies and demanding the rate concessions that go along with off-peak usage;
- Alternative energy forms—particularly in the industrial sector—by taking advantage of the ups and downs of prices in the petroleum, natural gas, and coal markets *vis a vis* electricity prices;
- Their investment for ours to become producers of electricity by both conventional and the so-called "soft" techniques such as wind and solar —in this way they not only compete with us to serve their own needs, but we are required to purchase their excess generation, usually at prices favoring the producer.

Monopoly, indeed!

Another factor that contributed to the rise of our industry was the fact that it became an increasingly vital element of production within the larger industrial system. Cheap electricity was the cornerstone of the aluminum industry and was also a critical resource to other manufacturers. The problem is not that electricity is becoming any less vital to heavy industry. The problem is that heavy industry in the United States is becoming increasingly subject to competition from lower-cost foreign sources. Autos, steel, and electronics are the best-known examples and we now hear serious, qualified observers questioning whether the USA will ever-again be fully competitive in these markets or whether we are evolving toward a high technology and service economy that will rely upon imports from other nations—where labor and energy may still be cheaper—for the bulk of our intermediate materials and capital goods. I don't know the answer, but the question itself carries frightening implications for the future growth of the electric power industry.

The problem is not that electricity is becoming any less vital to heavy industry. The problem is that the United States is becoming increasingly subject to competition from lower-cost foreign sources.

What about the political arena? Are we at last to find a positive element in our outlook? Not quite. On the national front, the first two years of the Reagan administration and the 97th Congress have produced mixed results. Here I do not intend to impugn the motives or even the effectiveness of the present administration. It seems, however, that the prevailing congressional view of the utilities—as expressed in legislation versus comment for public consumption—is only a little less negative than it was during the Carter years. Even so, there's certainly more reason now to be hopeful. But on the taxation front what Congress gave the utilities in 1981 and earlier was largely taken away in 1982. The major exception is dividend reinvestment, which was accorded tax preferential status last year and survived this year's reversal by the proverbial skin of its teeth.

The archaic Public Utility Holding Company Act—seen as obsolete even by the members of the SEC which enforces it—has not yet been repealed or modified to encourage greater business diversification. On the state and local front there are also disturbing signs. Wisconsin seems to be leading the way toward hamstringing the utilities in their efforts to offset the risk of

We are in a strange business. We are obliged to serve our customers' needs whether we can afford to do so or not.

the utility business through diversification. The National Association of Railroad and Utility Commissioners has opposed repeal of the Holding Company Act early, but its position may be softening.

Several states have seen the success of grass roots efforts to put anti-utility measures on the ballot. Such efforts include: Switches from appointed to elected PUCs; limitations on or disallowance of earnings on plant construction; anti-pancaking—which would prevent a utility from filing a rate case until the previous case had been decided; roll-backs of rates; and the elimination or restriction of adjustment clauses. We narrowly avoided an elected commission issue in Colorado.

Such grass-roots movements—frequently abetted by legislatures and governors—merely reflect what we all know to one extent or another: Our customers are damned unhappy with our rate increases and many of them are willing to try almost anything to stop them or slow them down.

We are in a strange business. We are obliged to serve our customers' needs whether we can afford to do so or not. We lose money on the sale of our product. We fight for the right to invest capital—whose true cost we cannot pay —in power plants nobody seems to want, so we can sell still more energy and lose money on it. Our customers are simultaneously involved in finding ways to use less of our product and to further limit the price we can charge them. The political system on which we depend more than any other business—for the life's blood of our revenue stream, responds to voters, most of whom are customers rather than employees or stockholders. Technology is seen by some to be antiquating our production processes and competition is eroding our sales, even as we bring huge amounts of new capacity into service.

Whether we agree with all of this or not is truly irrelevant to the basic problem. Sound arguments have and will be advanced on both sides of all the issues. But we cannot avoid the basic conclusion and its implication: Our business has become significantly more risky in the perception of the people who supply its basic need for vital capital. As a consequence, we are in serious jeopardy of losing our central position in the American economy unless we can improve our profitability. Investors will gladly accept more risk if we pay them to take it. They will not and should not accept it if another investment will give them a more favorable risk/reward balance.

We can improve our profits in three major ways:

1. Reduce operating costs to the lowest level and insist that the regulators allow us to keep the major portion of the savings that will result. I'm not talking about running cheapskate operations and abandoning our responsibilities, nor am I advocating so-called austerity programs. I'm suggesting the utility industry employ the best talent it can find to bring about a new and lasting commitment to modern management principles of cost control and efficiency. This will be helpful, but not sufficient.
2. Limit our investment in unprofitable new capital assets to the minimum consistent with adequate service. Again, we need management discipline to force ourselves to accept the risk of "not-building" on many occasions when our training and experience all tell us: "When in doubt, build." If we expect investors to increase their risk tolerance, we're going to have to reduce our own levels of comfort in the process. We're going to have to accept a higher risk that loads will be lost and some customers not served and, therefore, angry.
3. When we have minimized our operating costs and investments *and can prove it,* then and only then we must approach the regulators for higher prices. We must insist upon revenues adequate to pay the cost of making our product. We must inform our customers directly that we are well-managed companies, and that part of good management is to price the product fairly.

You'll say we've done all those things and still we're in trouble. I want to be the devil's advocate and ask every reader here whether he could prove to the satisfaction of an unbiased observer that every employee of every utility is pulling his weight, and that every part of the company is critical to maintaining acceptable service. If this is in fact the time when we are to be held accountable for the survival of our companies, are they as well-managed as utilities could and should be? If it is truly survival time, do we have the people in place who will take the action that is needed for survival?

If we are doing our job and our regulators will still not respond then we need not expect investors to respond either. Left to us will be three choices:

1. We can continue placing the obligation to serve above the obligation to be profitable, in which event we will ultimately bankrupt our companies.
2. We can look at our business as purely for profit and decline to make unprofitable investments, in which event we may ultimately violate the obligation to serve, with government ownership and other unpalatable consequences resulting.
3. We can work and pray for miracles including a reversal of our political fortunes, 6 percent interest rates, cheap coal, five-year nuclear construction cycles, deregulation of the industry, a positive technological breakthrough, wisdom to dawn in Washington, or (supply your own favorite miracle).

My non-economic forecast is that most of us will opt for one version or another of the third alternative while pressing hard to improve our costs and reduce our unprofitable investments. We will try to make a miraculous success of this industry for the same reasons that our contemporaries in steel and autos keep trying. We're human and we're in charge of the management of complex human institutions in very difficult times. It's always easy to cite and advocate some clever solution, but that solution may come at the cost of destroying the institution itself. There are limits to the magnitude of change that any institutional system can accept and we're struggling humanly with those limits here and now.

We may or may not succeed. After all, nothing lasts forever; but perhaps what is humanly important is not whether we succeed, but the quality of our effort and the optimism of our vision.

I'm reminded of the fellow who was brought before the king to be sentenced after his conviction on a capital change. The king decreed his execution and asked if the prisoner had anything to say.

This condemned man, no doubt a former employee of an electric utility, though about the problem and pondered the picture of the king before him—resplendent in his robes, sitting in great dignity upon his beloved white stallion.

"Your Majesty," said the prisoner, "I cannot argue that the sentence is unjust. However, you should be aware of my magical powers and, if you will delay my execution for one year, I will teach that magnificent horse to fly."

The king, contemplating the advantages a flying horse would give him versus his cousin kings in the neighboring realms, granted the stay of execution.

Back in prison, the fellow told his friends about the great deal he had just made. Naturally, they laughed and said, "you have no chance; you're just postponing the inevitable."

Our eternally optimistic employee replied, "Actually I have four chances. The king might die before a year. I might die. The horse might die. And, you know, I just *might* teach that animal to fly."

There are limits to the magnitude of change that any institutional system can accept and we're struggling humanly with those limits here and now.

WHY

Toward Energy Literacy: The Uncommon Accomplishments of an Uncommon Team

By Paul H. Schneiter

A model of cooperation, Energy & Man's Environment involves business and educational communities in teaching the nation about energy

"'Doing your own thing' is fine for button collectors or cave explorers, but not for energy educators—too much is at stake: jobs, quality of life, the well-being not only of this generation, but of generations to follow. Involving citizens at all levels of public and private life—that's the key."

Dr. Edward Dalton, President of Energy & Man's Environment (EME), knows what he's talking about. In the ten years since it was established, EME has become the nation's leading multipurpose energy education organization. From its headquarters in the heart of an industrial park adjacent to Salt Lake City International Airport, Dalton directs the nonprofit organization, which reached 17,634 educators with high-impact energy education programs last year. The effort was broadly based, involving 865 programs and 15 states (see Table 1).

The educators consisted of junior and senior high school teachers, elementary teachers, school administrators, and university instructors and staff members. They learned about energy—and how to teach others about it—in conferences, workshops, seminars, college credit courses, and a range of other instructional activities.

Obviously, a teacher training effort of this magnitude is more than Dalton and his four-member staff could hope to handle alone. They depend on four special groups of citizens to help them get the job done: coordinators and instructors, industrial and educational organizations and associations, the EME Board of Directors, and Sponsors' Advisory Committee. Together they function as a finely tuned team whose goal is to help make all U.S. citizens energy literate.

"Coordinators oversee EME programs and activities within particular geographic regions," Dalton explains. "Typically, they are community leaders, all of whom have strong educational backgrounds. They organize program planning and implementation committees. In turn, these committees organize and promote conferences for teachers to make them aware of EME's comprehensive energy educational services and materials and to help them understand the importance of energy as an issue to be studied in the classroom."

Consistent with EME's philosophy that an enlightened citizenry is central to coping with America's energy challenge, Dalton and his co-workers also make a concerted effort to involve parents, PTA leaders, volunteers, members of service clubs, and the general public in these awareness programs.

Following conferences, EME conducts implementation programs to provide educators with an in-depth look at global, national, and regional energy issues through presentations, demonstrations, and experiments.

"Teachers and administrators find these sessions stimulating because they deal with existing and projected sources of energy and their impacts," Dalton says. "The information is related to social, political, economic, and philosophical considerations. Lively, sometimes emotional exchanges are not uncommon, as the educators begin to understand some of the hard decisions society faces and the resulting energy and life quality tradeoffs."

Whether they teach kindergarten or twelfth grade, participants leave the implementation workshops armed with the materials and know-how

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Participants analyze specialized energy topics with a view to developing both resource materials for training educators and new instructional materials for teaching students.

Table 1. Programs and Participants by Region—1982

EME Service Region	Programs Conducted[1]	Educators Served[2]	Others Served[3]
Colorado	37	940	139
Dallas	13	641	505
El Paso	40	849	46
Idaho	42	514	2,453
Iowa	86	2,122	515
Kansas	119	2,881	701
Kansas City	118	1,782	11,511
Missouri	34	777	76
Montana	33	613	543
Nevada	29	922	32,502
New Hampshire	4	94	9
Odessa	1	66	0
Oregon	106	1,275	6,701
St. Louis	26	440	231
Tucson	17	302	147
Utah	46	1,013	7,026
Vermont	20	166	29
Washington	64	1,658	968
Wyoming	30	579	72
Totals	865	17,634	64,174

[1] Conferences, workshops, seminars, college credit courses, and other instructional activities.

[2] Junior and senior high school teachers, elementary teachers, school administrators, and university instructors/professional staff.

[3] Students and other participants (family members, general public, PTA members/volunteers, and members of service clubs and other civic organizations).

needed to start practicing energy education in earnest.

"Nothing is overlooked," says Heather Dunn, a junior high school science teacher from Denver who participated in an EME implementation workshop two years ago. "Energy education activities are rehearsed in the workshop, so when we get to our own classrooms, we know exactly how to proceed. It's a remarkably practical, detailed, 'hands-on' learning experience. And, it doesn't matter whether you're a science teacher or a football coach—some of the material is related to every discipline."

The instructional materials introduced and distributed at the implementation workshops were "years in the making," says Dr. Jon Thompson, EME's Vice-President. "They are teacher-designed and classroom-tested, and they are evaluated and refined regularly. They reflect the experience and best thinking of many accomplished content specialists. Importantly, the lesson plans and instructional activity ideas are not set in concrete—they're flexible enough to fit in with a variety of teaching strategies and each teacher's individual style. In addition, the materials are designed to mesh smoothly with any school district's existing curriculum."

"Take time to analyze EME's instructional materials," says Dr. Richard Peterson, of the Utah State Department of Education, one of the content specialists who worked with EME to help develop them, "and you'll find that they focus on seven basic energy concepts: (1) Sources of Energy, (2) Uses of Energy, (3) Conversion of Energy from One Form to Another, (4) Environment and Economic Impacts of Energy Development and Use, (5) Limited Nature of the Earth's Natural Resources, (6) Future of Energy Sources, and (7) Energy Conservation and Management."

EME regularly conducts seminars and university credit courses for content specialists. Participants analyze specialized energy topics with a view to developing both resource materials for training educators and new instructional materials for teaching students.

And, to meet the out-of-the-ordinary energy education needs that inevitably come along, EME conducts special programs ranging from debates and tours to lectures and technical briefings.

The second special group of involved citizens—EME's Board of Directors—are individuals with an in-depth understanding of energy and education. Ed Dalton's face lights up when he explains their contribution: "To say that they are a remarkable resource is not overstatement. Their leadership is pivotal. They bring uncommon foresight to policy-making matters. Functioning without them is unfathomable."

Alden Krieg, Executive Manager of Northwest Electric Light & Power Association, serves as Board Chairman. Krieg knows the value of teamwork. He talks enthusiastically of "the spirit of cooperation that EME has helped to build between the private and public sectors," and declares flatly that "EME processes and services *work*."

Krieg is assisted by Vice-Chairman Dr. A. D. Luke (Chief, Bureau of Instruction, Idaho State Department of Education); by Secretary-Treasurer Edward Prince (Manager of Communication Services, Pacific Power & Light Company); and by the following board members: Monte B. Davis (President, Pacific Coast Gas Association); Tina Butt (Principal, Apollo Elementary School, Issaquah, Washington); Kelly L. Jackson (Attorney, Nevada Consumer Advocate s Office); Vic Poirier (Manager, Community Affairs, Kansas City Power & Light Company); Walt Purdy (Manager, Education Services, Edison Electric Institute); Stanley D. Reed (Senior Principal, Engineering & Design Associates); William Rosol (Executive Manager, Rocky Mountain Electrical League); and Martin Shallenberger (Senior Public Affairs Representative, Standard Oil Company of Indiana).

Dalton meets with his Board three times each year, but he is on the phone with individual members almost weekly. "He calls about a lot of things," says Edison Electric's Walt Purdy. "He may want my reaction to a new energy education activity for junior high schoolers or my suggestions for a 'make 'n' take' project for educators who attend the implementation workshops."

In 1982, 119 corporations and organizations sponsored EME programs and projects, volunteered significant services, or made outright financial contributions to EME. Dalton is pleased not only by the number of sponsors and contributors, but by their diversity as well: "Utility companies are, understandably, well represented, but so, too, are manufacturing, petroleum, and engineering firms."

From the outset EME knew that it needed sponsors and contributors for more than their money. It needed their *ideas* as well. That decision led to the involvement of the third special group of citizens, the members of the EME Sponsor Advisory Committee.

"About 25 men and women presently serve on this committee," Dalton says. "We meet with them three times each year, exchanging ideas, critiquing suggestions, coordinating efforts. They share one concern in common: helping EME to help America become energy literate."

What do they receive in return? Janet Farr, committee representative for Kansas City Power & Light Company, puts it this way: "This involvement creates ownership in EME and assures that the corporation operates in an efficient and effective manner. That benefits every sponsor." Bill McTavish, Pacific Power & Light Company adds: "EME provides a service that our company can

Junior high school students working on an EME energy education lesson plan.

obtain in no other way, and they do it in a professional manner."

The fourth group of citizens—members of industrial and educational organizations and associations—covers a lot of territory. "I know there's risk in singling out individual institutions," Dalton says, "and yet I want to give credit where it's due." He points first to the roles of state departments of education and energy: "The highly committed men and women who staff these departments help make it all happen—they're in the front lines." Dalton also has high praise for area education agencies and the Education Commission of the States. He is grateful, too, for the support, encouragement, and counsel given over the years by the American Petroleum Institute, Rocky Mountain Electrical League, Pacific Coast Gas Association, Northwest Electric Light and Power Association, National Science Teachers Association, and the Edison Electric Institute.

Anyone else? "We are enthusiastic about the relationship that is developing between EME and the Energy Source Education Program," Dalton says. "Fred Niedermeyer at Energex, which developed the Energy Source Education Program, and EME are working toward teaming up to assure comprehensive distribution of instructional materials and training services to educators. That's a noteworthy development, not only because it extends our reach, but also because it suggests a new dimension in inter-agency cooperation . . . a constructive pooling of resources. This combination results in unsurpassable training services and materials for educators."

EME's leadership is not necessarily of one mind about the future. One board member believes priority should be given to converting printed instructional materials to a computer-assisted teaching format, while another feels a pressing need to devote more time toward improving volunteerism. About one thing they are of one mind, however: The need to make America energy literate will take on even greater urgency in the decade ahead, and if that need is to be met, EME must continue to involve the best minds it can find in education, private industry, and government.

EME Educational Materials

Assume, for a moment, that you have a box—It would have to be a big box—of EME instructional materials in front of you. Pick them up, look them over. What you will see is enough to excite anyone even remotely interested in energy education. Here's a sampling:

- Energy education lesson plans for kindergarten through Grade 3 and for Grades 4–6.
- Energy education lesson plans for Grades 7–9, covering Language Arts, Mathematics, Social Science, Science, and Vocational Education.
- Energy education lesson plans for Grades 10–12, covering Economics, Language Arts, Industrial Arts, Mathematics, Social Science, Science, and Vocational Education.
- *Energy Glossary,* a 32-page teacher's guide of over 900 energy terms and definitions—everything from *abatement* to *zone control.*
- *Humanities and Energy Activity Guide* to help secondary school teachers incorporate energy concepts into their humanities courses.
- Full-color posters for classroom display that verbally and graphically tell the story of natural gas, water, oil, coal, and other energy sources.
- *A Storybook Kit and Coloring Sheets about Natural Gas,* a colorful, interesting introduction to the history, uses, and future of natural gas (for younger children).
- *The Adventures of Mini-Volts and Wastey Watts,* a thoughtfully structured, multi-faceted learning activities kit designed to introduce kindergarten-age children to energy conservation.
- *The Energist,* tabloid-size newspapers that give teachers important, easy-to-grasp facts about primary energy sources—coal, natural gas, oil, water, etc.
- *Gushers 'n Dusters,* an educational simulation about the petroleum industry and the risks and challenges of exploring for oil and gas. All necessary materials are included in this comprehensive kit.

Clockwise from bottom left, EME resource materials, EME President Ed Dalton, and teacher's workshop.

"We have no intention," Dalton says, "of forgetting the lessons of our first decade. If our accomplishments can, in fact, be called 'uncommon'—as some have generously suggested—it is because we have had the good sense to rally to our side uncommon men and women who are united in their resolve to meet the energy challenge. We will continue on that course."

For more information about EME, write or call Dr. Edward Dalton at Energy & Man's Environment, 4980 West Amelia Earhart Drive, Salt Lake City, Utah 84116, (801) 539-1406

1982 Net Utility Plant Assets Up 10.8 Percent

As of December 31, 1982, net utility plant assets for all investor-owned utility operations were $274,072 million. Of this amount, construction work in progress (CWIP) totaled $90,320 million. During 1982, $17,537 million of gross utility plant was added, net utility plant increased by $26,725 million, and CWIP increased by $14,024 million. (See Table 1.)

Capitalization increased by $24,363 million during 1982, up 10.7 percent over 1981. The increase was used to meet the estimated 1982 cash construction expenditure requirements of $29.5 billion. The expenditures amounted to 12.3 percent of the average capitalization.

Common stock and retained earnings made up 39.1 percent of capitalization at the end of 1982, an increase of 1.1 percentage points over the previous year. Since the early 1970s, common shareholders equity has continually increased as a percentage of total capitalization. In 1982, in addition to common stock sold, an estimated $2,100 million of common stock issued through dividend reinvestment plans (including supplementary cash contributions), a relatively small amount issued through Employee Stock Option Plans, and retained earnings of about $3.6 billion all contributed to the increase in shareholders equity. Preferred stock decreased from 11.8 percent to 11.5 percent of capitalization, and long-term debt decreased from 50.2 percent to 49.4 percent of capitalization.

The 1982 data on the revised consolidated balance sheet are based on unaudited reports received from electric utilities. These reports accounted for over 92 percent of the industry's assets. Data were expanded to represent the entire investor-owned electric utility industry. The 1981 data from industry respondents were adjusted slightly to reconcile them with data published in the *1981 Statistical Year Book of the Electric Utility Industry.*

1982 Earnings Per Share Up 7.8 Percent

Investor-owned electric utilities earnings per share in 1982 increased 7.8 percent over 1981, up from $2.70 to $2.91. Net income available for common during the year increased 19.8 percent, but an 11.4 percent increase in average common shares outstanding diluted the income increase per share. The lower operating ratio (electric operating expense to electric operating revenue) of 82.0 percent in 1982, down from 1981's 82.7 percent, and the increase in return on equity earned both contributed to the yearly earnings increase. Also, allowance for funds used during construction (AFUDC) increased 27.7 percent for the year, and there was an additional $90 million of extraordinary income.

Fourth quarter 1982 earnings were down 9.4 percent from the fourth quarter of 1981. The 13.9 percent increase in average common shares outstanding converted a 4.6 percent increase in net income to a decrease in earnings per share. In 1982, the performance of earnings per share steadily lost momentum since the first quarter's 22.1 percent (revised) increase. The second quarter increase was 13.2 percent (revised), and the third quarter increase was 5.9 percent.

Investor-owned electric utility revenues rose 7.4 percent in 1982 to $101,246 million. The increase is the net result of the 6.3 percent increase in the average return on equity authorized during the year and the estimated 1.5 percent decrease in 1982 kilowatt-hour sales. Fourth quarter revenues were $24,104 million, up 3.4 percent over the fourth quarter of 1981.

In 1982, fuel expense declined to 43.5 percent of electric operating expenses; this ratio was 47.7 percent in 1981. At the same time, AFUDC increased to 46.9 percent of net income before preferred dividends; it was 43.4 percent in 1981. In the fourth quarter of 1982, AFUDC was 58.1 percent of net income before preferred dividends. The fourth quarter ratio in 1981 was 49.9 percent.

Interest coverage continues to show improvement at the industry level, but the improvement has not been large or concentrated enough at the company level to lead to more upgradings than downgradings in senior debt ratings. Interest coverage before income tax and

Contributed by the Finance department of Edison Electric Institute.

Table 1
INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY
BALANCE SHEET
(Unaudited)

Report as of December 31, 1982 and 1981

Revised

	(Millions of Dollars)		Change
Assets	**1982**	**1981****	**(%)**
Utility Plant*			
Utility Plant (Including Nuclear Fuel)	255,654	238,117	7.4
Less Accumulated Depreciation	71,902	67,066	7.2
Total	183,752	171,051	7.4
Construction Work in Progress***	90,320	76,296	18.4
Total Utility Plant (Less Accumulated Depreciation)	274,072	247,347	10.8
Investments	5,774	5,737	0.6
Current Assets	31,719	28,100	12.9
Deferred Debits	7,913	6,532	21.1
Total Assets	319,478	287,716	11.0
Liabilities			
Capitalization			
Common Stock	67,588	59,244	14.1
Retained Earnings	31,092	27,511	13.0
Preferred Stock	28,992	26,817	8.1
Long-Term Debt	124,826	114,563	9.0
Total Capitalization	252,498	228,135	10.7
Current Liabilities			
Short-Term Debt	7,102	8,185	(13.2)
Long-Term Debt Due Currently	3,319	3,202	3.7
Other Current Liabilities	23,285	21,008	10.8
Total Current Liabilities	33,706	32,395	4.0
Deferred Credits			
Accumulated Deferred Income Taxes	18,060	15,931	13.4
Accumulated Deferred Investment Tax Credits	10,326	8,271	24.8
Other Deferred Credits	4,888	2,984	63.8
Total Deferred Credits	33,274	27,186	22.4
Total Liabilities	319,478	287,716	11.0

*Includes other utility plant of combination gas and electric companies.

**Source: 1981 *Statistical Year Book* (Edison Electric Institute).

***Includes AFUDC.

with AFUDC was 2.72 for 1982 and 2.52 for 1981. Fourth quarter figures were 2.44 for 1982 and 2.40 for 1981.

Based on an average number of shares outstanding in each period, Edison Electric Institute estimates dividend growth was up 6.2 percent in 1982 over 1981.

The 1982 data given in Table 2 are based on unaudited reports received from electric utilities. These reports accounted for 94 percent of the industry's revenues. Data were expanded to represent the entire investor-owned electric utility industry. The 1981 data from industry respondents were adjusted slightly to reconcile them with data published in the *1981 Statistical Year Book of the Electric Utility Industry.*

Table 2
INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY
STATEMENT OF INCOME
(Unaudited, Millions of Dollars)

	Three Months Ended			Twelve Months Ended		
	December 31,		%	December 31,		%
	1982	1981 (R)	Change	1982	1981**	Change
Total Electric Operating Revenues	24,104	23,314	3.4	101,246	94,270	7.4
Electric Operating Expenses						
Fuel	8,384	9,090	(7.8)	36,134	37,163	(2.8)
Other Operation & Maintenance Expenses	6,302	5,751	9.6	24,737	21,677	14.1
Depreciation & Amortization	1,916	1,772	8.1	7,483	6,893	8.6
Taxes Other Than Income Taxes	1,728	1,580	9.4	7,187	6,565	9.5
Income Taxes (Federal & Other)	513	313	63.9	3,438	2,083	65.1
Provisions For Deferred Income Taxes—Net	654	625	4.6	1,911	2,208	(13.5)
Investment Tax Credit Adjustments—Net	357	269	32.7	2,141	1,333	60.6
Total Electric Operating Expenses	19,854	19,400	2.3	83,031	77,922	6.6
Electric Utility Operating Income	4,250	3,914	8.6	18,215	16,348	11.4
Other Utility Operating Income	133	183	(27.3)	1,058	1,031	2.6
Total Utility Operating Income	4,383	4,097	7.0	19,273	17,379	10.9
Other Income & Deductions—Net	218	492	(55.7)	1,549	1,733	(10.6)
Allowance For Other Funds Used During Construction	1,123	842	33.4	4,030	2,939	37.1
Total Income	5,724	5,431	5.4	24,852	22,051	12.7
Interest On Long-Term Debt	2,951	2,653	11.2	11,520	10,213	12.8
Other Interest Expenses & Charges	332	407	(18.4)	1,474	1,758	(16.2)
Allowance For Borrowed Funds Used in Construction (Cr.)	(755)	(692)	9.1	(2,979)	(2,550)	16.8
Total Interest & Charges	2,528	2,368	6.8	10,015	9,421	6.3
Net Income Before Extraordinary Items	3,196	3,063	4.3	14,837	12,630	17.5
Extraordinary Items	39	12	225.0	118	28	321.4
Net Income	3,235	3,075	5.2	14,955	12,658	18.1
Preferred Stock Dividends Declared	623	579	7.6	2,488	2,251	10.5
Net Income Available For Common	2,612	2,496	4.6	12,467	10,407	19.8
Common Stock Dividends	2,284	1,864	22.5	8,886	7,587	17.1
Retained Income	328	632	(48.1)	3,581	2,820	27.0
Earnings Per Share*	$ 0.58	$ 0.64	(9.4)	$ 2.91	$ 2.70(R)	7.8
Dividends Per Share*	$ 0.51	$ 0.47	8.5	$ 2.07	$ 1.95	6.2

*Based on average shares collected quarterly from respondents and adjusted for stock splits.

**Source: 1981 *Statistical Year Book* (Edison Electric Institute).

NOTE: The income statement is a "net" or "consolidated" statement. The duplicative effect of including resale revenues by one investor-owned electric utility to another has been eliminated.

Airlines Save On Cooling Costs

Ground cooling of aircraft cabins costs the nation's airlines more than $100 million a year in fuel alone, so the commercial airline industry was watching recently when Delta Airlines introduced a totally new ice-storage cooling system intended to slash ground cooling costs by more than 10 times at its new O'Hare Airport terminal in Chicago.

Aircraft are normally cooled, or heated, at the boarding gate by use of small onboard turbine engines called auxiliary power units (APU) located in the airplane's tail. The turbines drive generators that supply electrical power. Gas from the turbine's compressor is fed to an air-cycle cooling system that produces conditioned air for cooling, and heating.

The new equipment, recommended to Delta by conservation engineers at Commonwealth Edison, includes three 50-ton capacity electric drive compressors, located in the gate area, which produce ice during nighttime for use in cooling during daytime. A water/glycol solution is pumped to 14 storage tanks where the ice is actually manufactured. During the day, the water/glycol mixture is circulated through the storage tanks to a cooling coil at each gate where a 30-horsepower machine blows cool air into the airplane's cabin. The water/glycol mixture then returns to the storage tanks and is cooled again as the ice melts.

With the variety of aircraft Delta uses at O'Hare, APU fuel costs would average the company about $50 per hour for each gate. The ice storage system will reduce the hourly cost per gate to an estimated $3.50, with a reduction of electrical demand of some 60 percent.

Electric heating equipment, installed at each gate, will be used in winter.

The ice-storage cooling system benefits the utility as well, helping it to meet load management and conservation program objectives by shifting electrical use to nighttime, or off-peak hours, when electricity demand can be met by baseload nuclear stations. The peaking capacity required to meet higher daytime demands uses more costly fuels.

Institute Donates Historic Generator

On the occasion of the beginning of the second century of centralized electric service, the Edison Electric Institute donated funds for acquisition of a rare, 18th century glass globe electric generator reminiscent of the type Benjamin Franklin experimented with a century before Thomas Edison threw the switch to inaugurate commercial transmission of electric power from his Pearle Street station in 1882.

Now on exhibit in the Hall of Electricity in the Smithsonian Museum of American History in Washington, D.C., the Hauksbee-type glass globe generator dates to 1860. It is one of only two of its type on exhibit in the world.

These generators, developed and used between the 1740s and 1780s, proved that the formation of static electricity was not limited to glass tubes and silk cloth. With globe, leather pads to induce friction, and a turning mechanism, they were precursers of more advanced generators and higher forms of electric current manufacturing. During their day, they were used for scientific experimentation and entertainment.

Coupled with a Leyden jar, a storage container for electric current, globe generators produced in excess of 100,000 volts of static electricity. Today, that measure of current can be compared to the terrific shock one receives after shuffling one's feet on a carpet and then touching a grounded object like a door handle. This voltage figure reflects frictional energy, known for its high voltage and low current ratings; it cannot be accurately compared to today's processed electric current.

The luminescent properties of a turning globe prompted Franklin to continue his studies of electricity. Exhibited by a "fluid" appearance when the globe was in motion, this luminescence indicated that electricity was a product, not just a phenomenon.

The overall size of this table-top globe generator measures two feet in height and length and one foot in width.

Strategic Planning and Uncommitted Capacity

Uncommitted capacity is perhaps the most complex and perplexing issue the electric utility industry faces today. On the one hand, some public utility commissions have concluded that we have uncommitted capacity, overcapacity. On the other hand, a case can be made that we need to build new capacity, but we do not know how much. In fact, we may face a critical shortage in generation capacity within the next decade.

High reserve margins are symptomatic of the issue. Reserve margins are high by historical standards. Nationally, they have risen during the last decade from 20.9 percent in 1971 to 33.6 percent in 1981. We expect reserve margins to continue to rise for several more years and then decline as we approach the 1990s.

There is a growing opinion among some industry observers that these reserve margins are excessive. Looking at the average for the past four years, demonstrated capacity has exceeded peak demand by 25 percent. Five percent of this margin was used for scheduled maintenance, 7 percent for forced outages, and 5 percent for partial outages and deratings. Thus, 17 percent was unavailable for producing electricity. The remaining 8 percent was the effective operating margin. This 8 percent provided an opportunity for operating the most fuel efficient plants and only a small margin for future growth.

Therefore, even when we acknowledge the goal of reducing unavailability, it remains true that these seemingly ample reserves can be illusory, especially when we examine them regionally. In the mid-Atlantic region, for example, the operating margin was only 3 percent in 1981. Nevertheless, it is true that capacity margins are higher than expected when new and additional plants were planned.

How did this happen? Obviously, forecasts of electricity demand were inaccurate. Electricity has grown much more slowly than virtually anyone inside or outside the industry thought. What were the sources of the forecast inaccuracies?

Lewis Perl of National Economic Research Associates (NERA) recently reviewed some of the forecasts from the 1970s. He found that forecast error was not primarily the result of the methods or models used. The problem is the uncertainty associated with the inputs to the forecasting exercise. Growth in population, economic behavior, fuel/electricity prices, and other inputs to a forecast are themselves uncertain. NERA recently used its econometric demand model to "forecast" demand growth during the 1970s. As inputs, NERA was able to use the actual rather than the expected rates of growth of population, economic activity, and prices. The resulting "forecast" of growth matched actual growth almost precisely. "Thus," Perl concluded, "the failure in the past (and in the future) to produce precise forecasts does not result from poor models but from the difficulty in forecasting key inputs—uncertainties in forecasting economic growth, population growth, and fuel prices that will prove difficult to reduce."

In this time of great uncertainty, a planning horizon in which we can place reasonable confidence may be only a few years. But, construction lead times impose a timeframe of 8 to 15 years, depending upon the scale and technology involved. This mismatch can cause the adverse consequences of planning errors to accumulate over time.

Yet, even in a time when we must deal with the consequences of high demand forecasts and uncommitted generating capacity, we know that there is a danger of inadequate generating capacity as we look out into the future. In all regions of the country, the comfortable reserve margins planned for the 1990s depend upon coal and nuclear plant additions.

New capacity will be needed for three reasons: retirement of old plants, replacement of oil and gas capacity, and economic growth.

During the 1980s the industry will be operating an aging set of generating

Adapted from a speech delivered by Dr. Douglas C. Bauer, Senior Vice President of the Economics and Finance Group of Edison Electric Institute, at the Ninth Annual Rate Symposium, which was held in February in Kansas City. Contributed by the Rate Regulation department of Edison Electric Institute.

plants. For the past 30 years, the average plant age has remained about 10 years. By 1990, however, Bechtel expects average plant age to increase to 18 years. Eighty-nine gigawatts (GW) of capacity will be 40 or more years old in the next two decades. This implies increased maintenance, increased forced outages, and reduced real operating margins.

Existing oil and gas generation and even old coal capacity impose inefficiency costs on electric utilities which are borne by the economy as a whole. Shifts away from oil and gas are occurring because of conversions (in some cases reconversions) and additions. However, an extensive shift justified by cost considerations and security of supply is in jeopardy because of financial conditions and perceptions of overcapacity.

Thus, even if future economic growth is negligible, a substantial case can be made for completing the construction programs now in progress. Of course, we do expect the economy to recover from the current recession. But, the strength of the near term recovery and, more importantly, the outlook for growth over the entire lifecycle of the plants now being constructed is subject to great uncertainty. Also subject to uncertainty is the level of electricity demand that will be required with alternative economic growth rates.

One rendition of possible economic scenarios was prepared recently by the Electric Power Research Institute (EPRI). EPRI started with an industry projection, as reported to the National Electric Reliability Council (NERC) of a 2.9 percent annual growth rate for electricity demand from now to 1991. Then, based on analysis done at EPRI by Chauncey Starr and Milton Searle, researchers were able to associate a 2.1 percent GNP growth rate with the 2.9 percent electricity growth rate. The relationship between electricity and GNP is not intended to be precise, but is indicative of the close relationship between the two for the past 50 years, including the turbulent decade of the 1970s.

Alternative growth paths for the economy were then postulated—a 1.0 percent GNP growth path to represent continued stagnation and a 3.3 percent path to represent a resumption of healthy, yet moderate, economic growth. Again, based on historical relationships, electricity peak demand growth rates of 1.4 percent and 4.4 percent were imputed to the reduced and increased GNP growth, respectively. Finally, "needed new capacity" was derived for each growth case. These are 270 GW for the utility projection, 180 GW for reduced growth case, and 381 GW for increased growth case.

These needs can be compared to the planned new capacity of 200 GW. Under recent NERC projections of 270 GW, there would be a shortfall of 70 GW. Under the reduced case, the planned 200 GW exceeds the 180 GW needed, leaving 20 GW which does not fit into the 180 GW pie and which could be interpreted as uncommitted. When we swing back to the high growth case, a wide gap opens up—a shortfall of 181 GW.

Clearly, the electric utility industry is on a knife edge; whether or not we achieve a proper balance between capacity and demand will be determined largely by factors beyond our control, the nation's dependence on imported oil, the reliability of electricity supply produced with an aging set of plants, and the financial health of our industry, yet the outcome will have wide-ranging ramifications for costs imposed on our customers.

Needless to say, the industry is left in an uncomfortable position. While responsible and influential spokesmen from government and the industry express concern about adequate capacity in the future, the problem of uncommitted capacity has arisen at the same time construction programs are nearing completion. The consequences of the problem for electric utilities include charges of mismanagement, unfavorable public perceptions, opposition to needed facilities, and, potentially, adverse rate treatment. The problem is increasingly entering public utility commission consideration in the form of excess capacity determinations.

Treatment of excess capacity varies greatly, not only from state to state, but even from case to case within a state. However, in very general terms, five categories of commission treatment can be identified:

1. New capacity can be excluded

from rate base, as constituting uncommitted capacity, not used and useful to serve the utility's customers. The classic instance of this treatment is the 1980 Missouri commission decision excluding Kansas City Power & Light's Iatan station from rate base.

2. A utility's oldest or least efficient units can be excluded from rate base, on a finding of overall excess capacity. The Pennsylvania commission adopted the approach in a 1981 Philadelphia Electric rate case, eliminating the depreciated original costs of PE's least economical units from rate base.
3. Adjustments can be made to rate of return. This has become the standard policy of the Iowa commission. A progressive penalty to return on equity is imposed on Iowa utilities which have reserve margins in excess of 25 percent.
4. Adjustments can be made to operating expenses, or to revenue requirements. For instance, the Minnesota commission removed O&M expenses related to old, oil-fired stations from Minnesota Power & Light's operating expenses, while allowing MP&L to keep the stations in rate base. The New York commission has imputed off-system sales at the "highest reasonably obtainable level" to Niagara Mohawk Power's operating income, characterizing this approach as "more responsibl[e]" than rate base adjustments.
5. The commission takes no punitive action, for any of a wide variety of reasons. It may find that no uncommitted capacity exists. Normally, whether a given capacity level is excessive is determined individually for each utility. Or the commission may find penalties inappropriate. The Wisconsin Commission declined last year to impose a penalty on Wisconsin Public Service, which had a 51 percent reserve margin after bringing a new plant on line, because WPS had made efforts to sell the excess capacity, and consumers were benefitting from lower fuel costs from the new plant. Last January, the Indiana Commission allowed Public Service Indiana to include a new plant in its rate base, although the plant raised PSI's reserve margin to 47.3 percent, reasoning that periods of high reserve margins were the necessary consequence of adding capacity in large increments, and that the alternative, smaller, less efficient units, was not in the ratepayers' best interest. In a 1982 Sierra Pacific Power case, the Nevada commission "found compelling" Peter Navarro's article *The Soft, Hard or Smart Path: Charting the Electric Utility Industry's Future*, and found a unit "useful" if it "Reduce(d) the net cost of providing service."

It is difficult to generalize how commissions are handling the issue. There is no definition of excess capacity that is consistent for decisions made thus far. Treatment of excess capacity is not only region specific but at times utility specific. EEI reviewed 11 cases in which excess capacity was a significant issue. The cases were reported in detail to your rate departments by EEI's URAP system. In eight of the cases the commissions decided that no adjustment was necessary although the considerations varied in each case. In one case a revenue adjustment was made. In the remaining two cases, excess capacity was excluded from the rate base and a rate of return was denied.

In sum, the industry is faced with an extremely complex problem with which a number of constituencies will be involved in resolving:

General Public—Little concern about capacity and continued reliability of service. Utilities have the capital needed for any new construction. Suspicion that many nuclear plants will be abandoned from either safety or demand reasons. More than 50 percent view electricity as a right.

Activist public—Aware of high reserve margins and employ that to oppose new construction. Danger that the *fact* of high reserve margins for one company may be generalized to the *perception* of high margins for other companies and the industry as a whole.

Business—Dependent upon adequate and reliable supply. Will make investment and electricity demand decisions accordingly.

Government—Rethinking role of government in utility affairs (DOE policy project).

Commissions—Sit in judgment of uncommitted capacity. Highly diverse. Increasingly politicized and controlled by near term arguments rather than life-cycle economics (whether elected or appointed).

The electric companies are confronted with a Gordian knot, yet because of both our limited authority (subject to diverse constituencies) and the uncertain future, a quick, bold solution is not readily apparent. Each company must decide whether to build, continue to build, or not build a given plant. Simply to delay a decision in order to accumulate more information may not be prudent. Capital intensive plants are increasingly subject to cost overruns. The harsh political and regulatory climate imposes delays. These delays are not without costs. For example, a reduction in construction time from 14 to 9 years could mean a reduction in costs of 65 percent.

We are presented with one of the most important planning problems facing the industry today. It transcends system planning, engineering, finance, government affairs—virtually all aspects of the electricity business.

The public also must be involved in this decisionmaking. A public assumption that we have excess capacity may be just as damaging as an industry assumption that vigorous economic growth and a tight correlation between economic and electricity growth will continue. We must be sensitive to the reactions of our customers (residential, commercial, and industrial) to our dilemma. Their reaction will affect demand, rate treatment, even our self-image as an industry.

A solution to the problem will come one way or another with time. Uncertainty will play a significant role. The results will be different in different settings. However, if the full weight and wisdom of this industry is to be effective, we must consider a wide range of possible "futures" and sharpen our tools to evaluate strategies to react to them.

The Cost of Energy in Manufactured Goods

Despite the rapid rise in energy prices between 1977 and 1980, the cost of energy remains a relatively minor factor in the cost of most manufactured goods. Between 1977 and 1980 the cost of energy as a share of the value of total products shipped increased from 2.84 percent to 2.92 percent. Electricity costs increased from 1.23 percent in 1977 to 1.32 percent in 1980.

Table 1 identifies the 25 industries with the highest cost of purchased electricity as a percentage of the value of product shipments in 1980, as well as the 1977 percentages. Since 1977, five industries—pressed and molded pulp goods, primary nonferrous metals, pulp mills, metal heat treating, and noncellulosic organic fibers—dropped from the list. They were replaced by the structural clay products, rayon and acetate fiber, glass containers, gray iron castings, and carbon black industries.

Only four of the industries listed in Table 1 experienced decreased electricity costs, and of those, only manufactured ice showed a large decrease. Nonetheless, the cost of electricity was over 10 percent of the value of product shipments for only four industries in 1980 compared to six industries in 1977. Industrial gases, alkalies and chlorine, primary zinc, reclaimed rubber, and rayon and acetate fiber showed the largest increases.

The combined cost of total purchased electricity and fuels as a share of the value of product shipments also

Table 1. Industries With the Highest Cost of Purchased Electricity as a Percent of Value of Product Shipment

Industry	Percent Cost of Electricity to Value of Shipment 1980	1977
Industrial Gases	24.14	21.31
Primary Aluminum	16.97	15.27
Alkalies and Chlorine	14.18	11.95
Electrometallurgical Products	13.88	14.08
Industrial Inorganic Chemicals*	9.46	12.19
Primary Zinc	8.95	5.73
Reclaimed Rubber	8.43	3.41
Cement, Hydraulic	8.38	8.01
Malleable Iron Foundries	7.39	5.42
Paperboard Mills	6.81	6.69
Building Paper and Board Mills	6.79	5.22
Paper Mills, except Building Paper	6.20	5.32
Lime	5.04	4.39
Manufactured Ice	5.02	10.24
Particleboard	4.63	4.34
Carbon and Graphite Products	4.48	4.36
Brick and Structural Clay Tile	4.36	3.43
Mineral Wool	4.18	3.37
Steel Foundries*	4.04	3.55
Structural Clay Products*	3.88	2.45
Rayon and Acetate Fiber	3.72	1.27
Glass Containers	3.65	3.06
Gray Iron Castings	3.62	2.63
Nitrogenous Fertilizers	3.60	4.00
Carbon Black	3.49	2.98

*Not Elsewhere Classified

Table 2. Industries With the Highest Total Cost of Electric Energy and Fuels as a Percent of Value of Product Shipment

Industry	Percent Cost of Fuels and Purchased Electricity to Value of Shipment 1980	1977
Lime	32.77	33.85
Paperboard Mills	28.92	31.87
Industrial Gases	26.13	25.16
Rayon and Acetate Fiber	26.09	9.96
Cement, Hydraulic	24.59	25.59
Brick and Structural Clay Tile	24.07	18.38
Structural Clay Products*	22.77	15.81
Alkalies and Chlorine	21.25	21.36
Building Paper and Board Mills	21.03	14.80
Primary Aluminum	19.90	17.57
Paper Mills, except Building Paper	18.81	16.81
Electrometallurgical Products	17.53	18.14
Nitrogenous Fertilizers	16.86	16.21
Beet Sugar	16.51	21.35
Pulp Mills	15.46	15.07
Industrial Inorganic Chemicals*	14.95	17.09
Primary Zinc	13.76	14.09
Blast Furnaces and Steel Mills	12.36	10.57
Malleable Iron Castings	12.00	9.41
Carbon Black	11.97	10.70
Gypsum Products	11.88	11.00
Reclaimed Rubber	11.80	5.37
Manufactured Ice	11.71	11.02
Glass Containers	11.69	9.98
Wet Corn Milling	11.68	11.33

*Not Elsewhere Classified

increased slightly between 1977 and 1980. As shown in Table 2, among the 25 industries with the highest energy costs in 1980, the rayon and acetate fiber, brick and structural clay tile, structural clay products, building paper and board mills, and reclaimed rubber industries experienced the biggest increases. Only 8 of those top 25 industries experienced a decrease in energy cost as a percentage of the value of product shipments since 1977. Moreover, the decrease was large only in the sugar beet industry. In 1980 the cost of energy was over 20 percent of the value of the product shipments in nine industries compared to six industries in 1977.

The source for this data is the U.S. Bureau of the Census 1980 Annual Survey of Manufacturers.

Megatrends: Ten New Directions Transforming Our Lives

John Naisbitt
Warner Books, 1982
New York, New York 290 pp.

By Charles Linderman

John Naisbitt has written a valuable book that raises many questions, but provides few answers. The tough answers electric utilities need about the future are not forthcoming in the text. Nor are his conclusions regarding the ten new directions of American industrial society insightful as to their ultimate effect on the power industry.

For example, a key for business in Naisbitt's view is to know the business one is in. He asserts that utilities ". . . have been in the business of winning rate cases; now they must reexamine what business they are in as the industry is deregulated and decentralized." Although signs of decentralization in the electric utility industry may be occurring through the development of cogeneration power sources, the future of industry regulation is not as certain, especially when one considers such things as increasing public assertiveness over rates, safety (particularly with regard to nuclear plants), and the formulation and implementation of future plans.

Naisbitt also speaks to the electric utility industry when he addresses the need for high-technology skills in the future. "The lack of skilled workers is most alarming in the area of nuclear power," he says, going on to cite Three Mile Island, North Anna One, Crystal River, Rancho-Seco, and Davis-Besse plants as examples of operations having personnel insufficiently trained in one way or another. The fact that a limited number of individuals in college are choosing careers in the nuclear power business is discussed, and the inference may be drawn that there will not be sufficient numbers of trained staff to man nuclear plants in the future. Needless to say, the industry has long been aware of this potential problem and has developed several training and recruitment programs to address it.

Megatrends
Ten New Directions Transforming Our Lives
John Naisbitt

One hypothesis Naisbitt asserts throughout the book is that our industrial infrastructure is changing radically and the "reindustrialization" is not the key to future prosperity. What is needed, he argues, is "Rather than reinvest in the industries that once made us great, we must move beyond the industrial tasks of the past, toward the great new enterprises of the future." His argument, however, leaves a number of persistent questions: Can a society with high-technology and high-defense needs manage those needs without heavy industry? Can we rely only on computer-software, electronics, and consumer goods as the economic basis of a nation? From this reviewer's perspective, it seems that our society needs to apply the best of technology and electronics to our coal, steel, automobile, and manufacturing industries. Technology must be made to modernize work for all involved in producing in our society's infrastructure.

At the same time, Naisbitt wisely notes the resistance to technological change found in many elements in our society, and he discusses carefully customer resistance to technological change that could permit electric utilities such things as better load manage-

Charles Linderman is Manager of Fossil Fuel Programs at Edison Electric Institute.

ment and automatic computer meter reading. As utilities implement new plans and controls, they may need to communicate better with people who will be affected by these changes.

The topic of communication also arises when Naisbitt addresses the subject of managerial organization. He emphasizes networking as a means of organization in lieu of the traditional pyramid, or top-down management typical of large organizations like utilities. "Simply stated, networks are people talking to each other, sharing ideas, information, and resources," Naisbitt says. Often citing the Japanese' use of networking, he explains that the point is often made that networking is a verb, not a noun. The important part is not the network, the finished product, but the process of getting there—the communication that creates the linkages between people and clusters of people.

In short, *Megatrends'* significance for the electric utility industry may lie not in its particular speculation on trends for the future, but in the questions it raises in the reader's mind, questions as diverse as the challenges facing utilities. Some of these questions are related to the environment and our future power sources: Will railroad coal transportation costs force the development of mine-mouth generating companies or slurry pipelines; does the development of cogeneration and low-head hydro lead to an industry not as reliant on central generating situations in the future; and are we ready to take the human resources steps necessary to accommodate the wide-spread employment of two-careers couples? Because it prompts such questions, *Megatrends* merits reading.

CALENDAR OF MEETINGS
Edison Electric Institute

When
What
Where
Who to Contact
(Call 202/828-7400)

July 18–22
EEI Tax Seminar
Dallas, Texas
Ted Gradin

August 15–17
EEI Training Directors' Institute
Atlanta, Georgia
Frances Palladini

August 22–24
EEI Economic Development Committee Meeting & Workshop
Denver, Colorado
Charles Taylor

September 19–21
EEI Annual Roundtable Conference
Chicago, Illinois
Frances Palladini

September 19–21
EEI Rate Research Committee
San Francisco, California
David Owens

September 19–21
EEI Fire Protection Committee
Boston, Massachusetts
James Evans

September 19–21
EEI Meter & Service Committee
Dearborn, Michigan
David Soffrin

September 20–23
AGA-EEI General & Plant Accounting Committees
San Antonio, Texas
George Brown

September 20–23
EEI Residential Committee Meeting & Roundtable
St. Louis, Missouri
Robert Griffin

September 25–28
EEI Commercial/Industrial Committee Meeting & Workshop
St. Louis, Missouri
Charles Taylor

September 25–28
EEI Risk Management Committee
Phoenix, Arizona
Ted Gradin

September 26–27
EEI Construction Committee
Salt Lake City, Utah
Eric Haskins

September 26–28
AGA-EEI Budgeting & Financial Forecasting Committees
Denver, Colorado
Lowell Klosky

October 2–5
EEI Nuclear Operations Committee
Hampton, New Hampshire
Suzanne Phelps

October 2–5
EEI Prime Movers Committee
Portland, Oregon
James Evans

October 4–6
Electric Vehicle Council
EV EXPO '83 Electric Vehicle Exposition & Conference
Dearborn, Michigan
John Makulowich

October 5
EEI CS&M Executive Advisory Committee
Albuquerque, New Mexico
Charles Taylor

October 6–7
EEI CS&M Division Executives' Symposium
Albuquerque, New Mexico
Charles Taylor

October 5–7
EEI Statistical Committee
San Francisco, California
Thomas Daugherty

October 5–7
AGA-EEI Internal Auditing Committees
Tampa, Florida
Marshall Baker

October 6–9
EEI Legal Committee
New York, New York
Robert Baum

October 9–11
EEI Compensation & Benefits Committee
New Orleans, Louisiana
James Stroop

October 9–12
EEI System Planning Committee
Philadelphia, Pennsylvania
Jamei Goellner

October 10–12
EEI Financial Conference
Palm Beach, Florida
Ted Gradin

October 10–12
EEI Security Committee
St. Louis, Missouri
Eric Haskins

October 10–14
EEI Transmission & Distribution Committee
Denver, Colorado
David Soffrin

October 12–14
AGA-EEI Depreciation Accounting Committee
New Orleans, Louisiana
George Brown

October 16–19
EEI Consumer Affairs Committee Meeting & Conference
Washington, D.C.
Charles Taylor

October 19–20
EEI Hydraulic Power Committee
Denver, Colorado
James Evans

October 23–26
EEI Street & Highway Lighting Task Force Meeting & Workshop
St. Louis, Missouri
Charles Taylor

October 24–26
EEI Electrical System & Equipment Committee
Minneapolis, Minnesota
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October 30–
November 2
EEI Taxation Committee
Charleston, South Carolina
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November 7–9
EEI Claims Committee
San Diego, California
Robert Baum

November 6–9
EEI Safety & Industrial Health Committee
Dallas, Texas
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November 6–9
AGA-EEI Customer Services Committees
San Diego, California
Robert Griffin

November 16–18
AGA-EEI Information Systems Conference
Kansas City, Missouri
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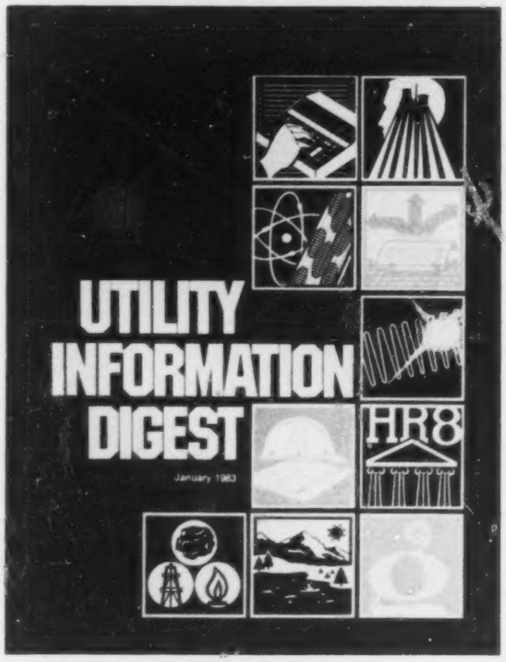

UTILITY INFORMATION DIGEST

It is increasingly difficult to keep up with the deluge of publications we all feel we should read. They range from the many trade magazines—*Electrical World, Electric Light & Power*—to the general news publications—*Time, Business Week*—to the thought leading publications—*Fortune, The Economist.*

Not only do we feel snowed by the increasing volume of information being transmitted, but information is being made available to us at a faster rate than anyone can be expected to absorb it. Meanwhile, the pace of events is shortening the lead time for developing well-researched decisions, and government regulation, deregulation, public attitudes, corporate responsibility, and other factors are adding difficult—sometimes touchy—considerations.

There's a problem—and Edison Electric Institute has come up with something to help—a monthly service called *Utility Information Digest*. The *Digest* tracks at least 100 of the most widely-read magazines and periodicals affecting the industry and prepares abstracts of significant items. What makes the service most valuable is its thorough cross reference index. By utilizing keywords, *Utility Information Digest* subscribers are able to locate all articles on a vast number of topics.

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Fall 1983

Electric Perspectives

Hydro Relicensing

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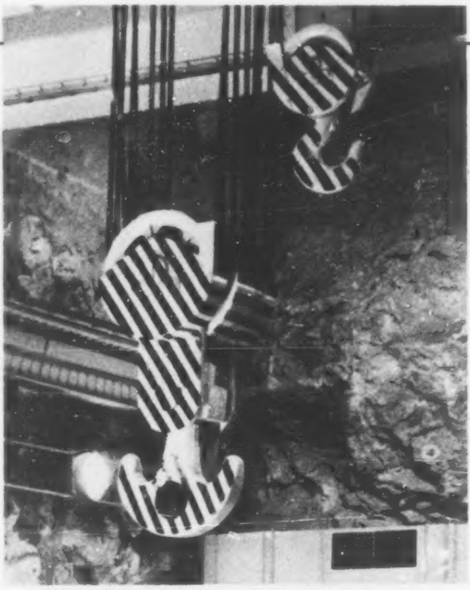

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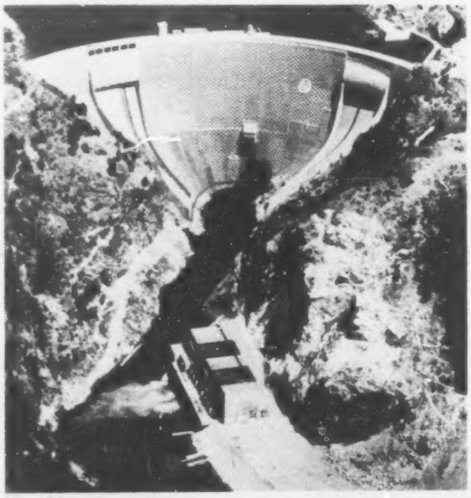

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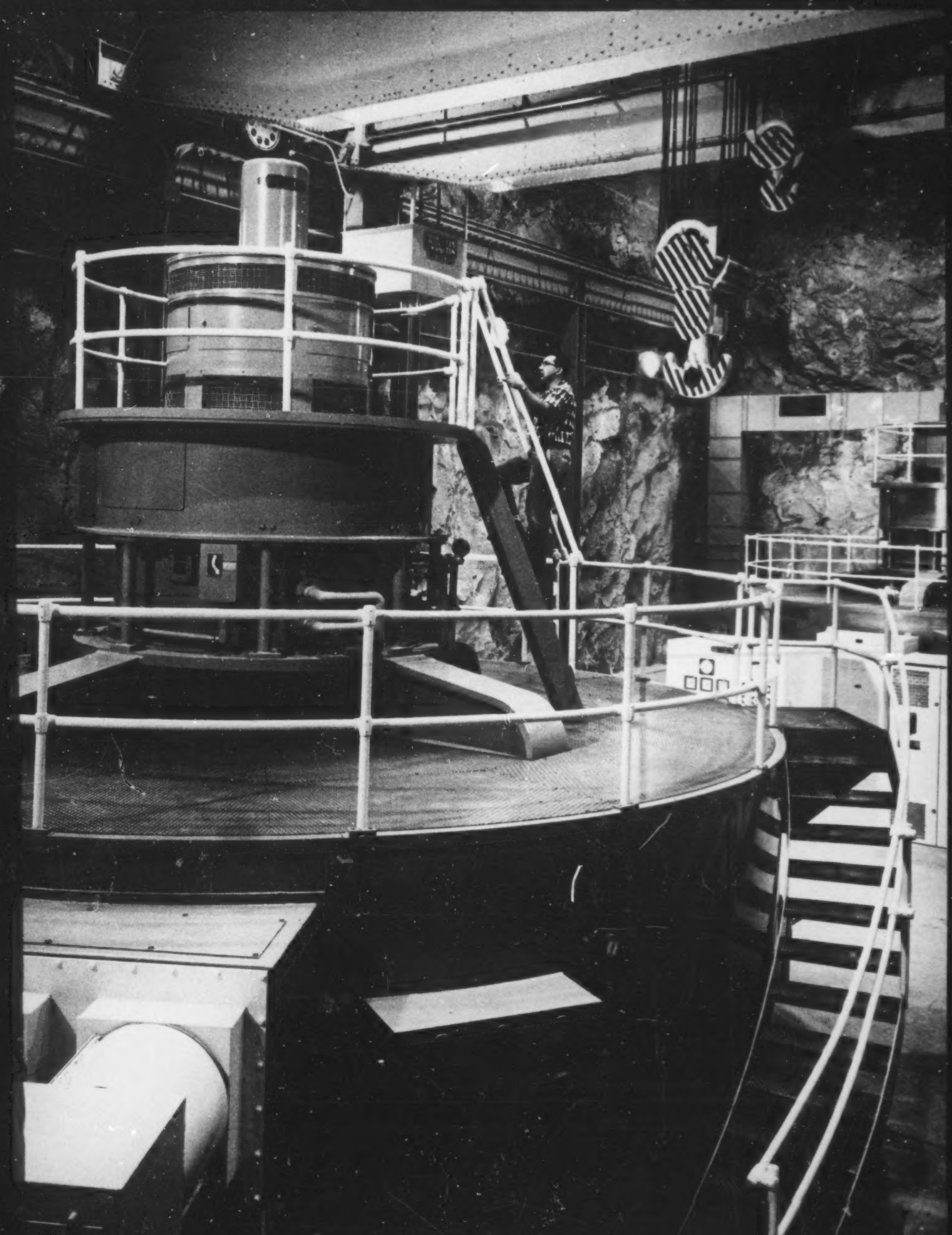
COVER
The relicensing competition for hydroelectric power projects has both short- and long-term significance for the investor-owned utility industry as well as the many millions of customers it serves

Illustration by Michael J. McGurk



Now And In The Future

By Joseph M. Farley

A look at the impact of the relicensing competition for hydroelectric power projects

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In 1980, the Federal Energy Regulatory Commission (FERC) made a decision that surprised—indeed, shocked—many people in the electric power industry. The effects of that decision will be felt by electric utility customers across the country.

Among other things, FERC regulates the licensing of hydroelectric plants. In 1980, it reversed a 1967 interpretation of its predecessor, the Federal Power Commission, and determined that states and municipalities can take over licenses for existing hydroelectric projects at the time of relicensing simply by showing that their plans for the continued operation of the project are merely as good as, but no better than the existing license holder's. Put simply, states and municipalities are preferred as against the present operator of the project at the time of relicensing. Thus, when a license expires—often 50 years after it was first issued—an investor-owned utility can lose its hydro plant to a municipality that wants it.

As of July 1983, competitors claiming a municipal preference had filed competing applications for eleven projects that have come up for relicensing so far. Approximately 168 hydro projects of utilities across the county will be up for relicensing by December 1993. (See map depicting location of the 168 projects.) These competitors seek a forced transfer of hydroelectric projects which investor-owned utilities have developed, operated and maintained for years with funds initially supplied by their investors but ultimately paid through the rate making process by their millions of customers. The federal government's hydro license-regulating agency has interpreted the law to the detriment of these millions of customers and a federal appellate court has deferred to that agency's analysis. The U.S. Supreme Court on July 6, 1983, declined to hear the case, although FERC had asked that its 1980 decision be remanded to it for reconsideration.

Not surprisingly, investor-owned utilities (hereafter referred to as utilities) are concerned about the government's decision since they own and operate many of the nation's hydroelectric plants—plants that save millions of electric customers billions of dollars. These companies and their customers believe Congress should now review this matter and determine where the public interest lies.

Getting the Original Hydro License

In 1920, when the nation was just beginning to recover from a devastating war, Congress passed the Federal Water Power Act; this Act created the Federal Power Commission. (This Act became the Federal Power Act in 1935.) One basic goal of the Act was to encourage private investors to develop the hydropower resources located across the nation. The Commission's job was to see that this happened by issuing licenses to develop those resources, conditioned so as to protect the public interest.

Utilities, backed by private investors, willing to take the risk of developing those resources and able to demonstrate their ability to utilize and conserve the water resources of the region in the public interest, were granted licenses to own and operate hydropower projects. Some of these utilities now have owned, operated and maintained their hydro plants for 50 to 75 years. The associated costs have been borne by the utilities' millions of customers.

Although Congress in 1920 wanted private investors to develop and use

Joseph Farley is President and Chief Executive Officer of Alabama Power Company.

Pacific Gas and Electric Company's Haas-Kings River Project is object in part of a takeover attempt by a consortium of 18 municipalities. The company's Haas Powerhouse is pictured opposite.

If the prevailing interpretation of the relicensing provision is followed, during the next 20 to 30 years nearly all of the hydroelectric projects in the country could be under license to municipalities.

hydropower resources in the public interest, the lawmakers nevertheless gave states and municipalities a "preference" over private investors in obtaining *the original* license to own and operate hydro plants. The Act's "preference" clause for the original licenses works like this: If an investor-owned utility and a state or municipality are competing for a license to build and operate a hydroelectric project at an undeveloped site, the state or municipality need only submit a plan that is essentially the same, "equally well adapted," as the utility's in order to be awarded the license. The state or municipality need not have a better plan.

The preference clause notwithstanding, utilities received many of the original licenses to build, own, and operate hydro plants. They spent many millions of dollars building the facilities and more millions operating and maintaining the plants. The value of these plants today is many times their original value, and they have been incorporated in the utilities' overall generating systems. In fact, in some cases the systems have been built around the projects. In many cases, the hydro projects are the most economic of the utilities' generating plants.

Relicensing of Developed Projects

Until recently, utilities had little reason to think being relicensed would be other than a routine procedure. In 1968, for example, the Federal Power Commission, predecessor of FERC, in advising Congress with respect to certain proposed amendments to the Federal Power Act which were designed to facilitate relicensing of projects, the terms of which are expiring, testified:

> "that the existing provisions of section 7(a) of the Federal Power Act, which gives States and municipalities preference in issuing licenses for new projects, is not applicable at the time of relicensing in a contest between the existing licensee and a party seeking to replace it as the licensee. This, we believe, means that in such a contest the new license will go to the party which can best meet the comprehensive development standards of the act, and if the original licensee can meet these standards as well as the new applicant, we believe he should secure the license."

Also, some utilities that had already filed for a new license before 1980 when their existing license expired, received those licenses from FERC; however, no state or municipality had filed a competing application for those new licenses.

The situation is different now:

- Applicants claiming preference are presently competing with utilities for 11 of the utilities' hydroelectric projects.
- In June 1980, FERC declared for the first time that states and municipalities had a preference under the law, not only in the original licensing of hydro projects, but in their relicensing as well.
- Several utilities which could ultimately be affected by FERC's 1980 interpretation appealed the Commission's decision.
- In September 1982, the U.S. Court of Appeals for the Eleventh Circuit affirmed the ruling by deferring to FERC's 1980 interpretation.
- In October 1982, the utilities asked the U.S. Supreme Court to review the 11th Circuit ruling, but in July 1983, the Court declined to take the case.
- In the first competitive relicensing case before the Commission since its 1980 decision, a FERC Administrative Law Judge, in April 1983, recommended that the competing municipalities be awarded the license to own and operate the utility's hydro project.

By the end of 1993, licenses for approximately 168 hydro projects throughout the country, many of which include more than one dam and powerhouse, will expire. If the 11 competitive cases are any indication, and in light of continued increases in electric rates which are foreseeable, municipalities can be expected to challenge the relicensing of many, if not all, of these hydro projects which of course require no fuel consumption in their operation.

If the prevailing interpretation of the relicensing provision is followed, during the next 20 to 30 years nearly all of the hydroelectric projects in the country could be under license to municipalities. The benefits of these projects would be concentrated in the municipalities' relatively fewer customers rather than remaining with the utilities' millions of customers. The utilities can be expected to take a stand on this issue on their customers' behalf. The equities are clear:

- The economic benefits of hydroelectric resources should be shared by the millions of utility customers and not limited to the relatively few customers of municipalities; utilities—which have brought the benefits of hydro-generated electricity to many millions of people--have been operating these projects in the public interest for several decades.
- The utilities and their shareholders assumed the risks of developing these projects and the utilities and their customers have paid for the construction, operation, and maintenance of these projects for as many as 50 years.

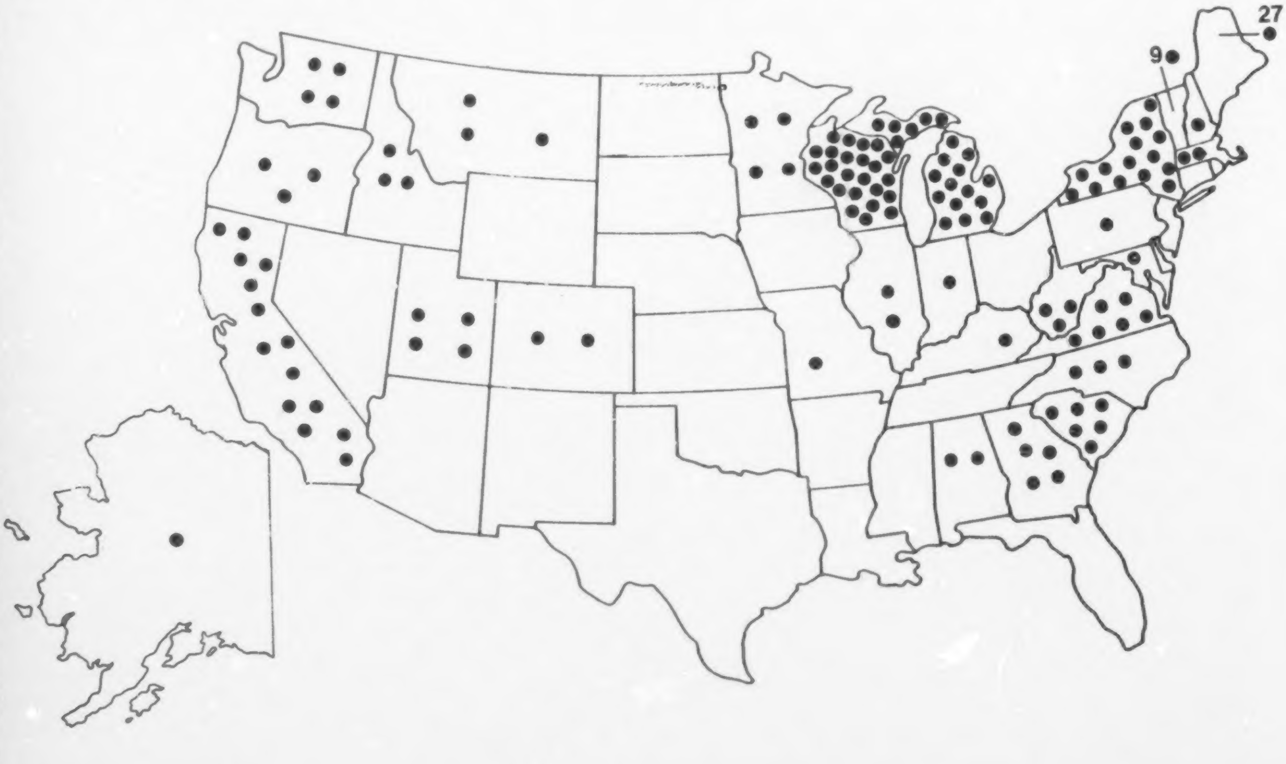
This issue must be brought to the attention of all utility customers and their representatives at all levels of government so they can critically examine this issue for themselves.

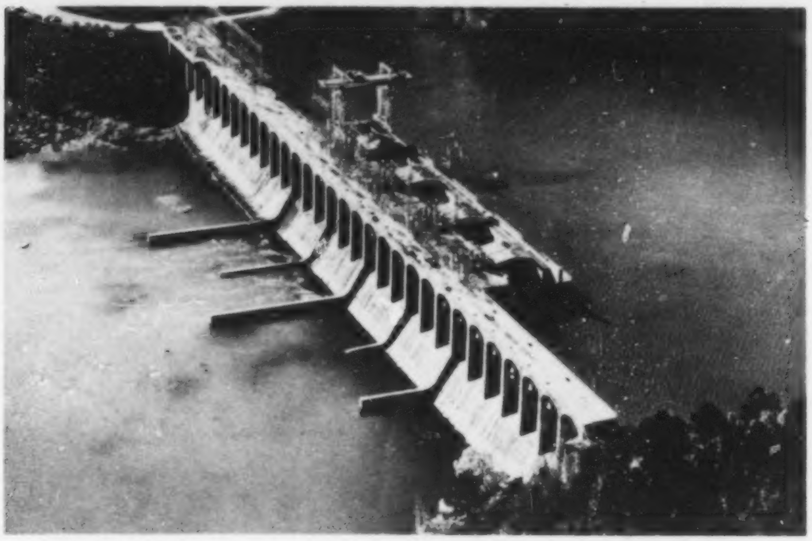
The Utilities' Argument

For decades, municipalities and their relatively fewer electric customers have been "preferred" recipients of the numerous benefits of hydro power from many of the nation's hydro projects including those which have been developed or operated by the federal government or one of its agencies such as the Bureau of Reclamation and the Army Corps of Engineers. The primary benefit of hydro power is that it can be used to generate electricity without burning costly fuels such as oil or gas. Consequently, this electricity generally costs less than electricity generated by other means. Many municipalities already are "preferred" customers of hydroelectric power produced at projects built by federal agencies such as the Bureau of Reclamation and the Army Corps of Engineers. Such taxpayer-subsidized federal projects make up approximately 47 percent of the nation's hydroelectric capacity. In 1981 these federal projects generated approximately 49 percent of the nation's hydroelectricity. Most of the power generated at these federal projects is delivered to the relatively fewer customers of municipalities and to other "preferred" customers.

Of the seven municipal groups that

Investor-owned utility hydroelectric projects in the United States up for relicensing by January 1, 1994.





Alabama Power Company paid more than $14 million in state hydro generation taxes during the last decade. The company's Mitchell Dam project is pictured above.

have electric customers and that are claiming a preference in the current relicensing of 11 hydro plants, four are already "preferred" recipients of low-cost hydropower from federal projects. This low-cost power is a major factor in many municipalities' ability to charge rates lower than the utilities in the same geographic areas.

In addition, five of these seven groups are now wholesale customers of the utilities whose hydro projects they are seeking to take over. As wholesale customers, the municipalities' electric customers receive the same fuel cost and other benefits from hydro-electricity as do the utilities' other customers.

Moreover, three of the competing municipal groups and their customers presently benefit from *both* federal hydro projects and from utilities' hydro projects through wholesale power purchases. If these municipalities take over the utilities' hydro at relicenseing, they will continue to benefit from the federal projects; in addition, however, the municipalities' relatively fewer customers will become the exclusive beneficiaries of the no-fuel-cost hydroelectricity.

Municipalities also enjoy significant tax breaks and subsidies. For example, in many areas of the country, the municipalities seeking licenses now held by utilities would not be required to pay the state and local taxes associated with the hydroelectric projects that utilities have paid for many years. Such taxes are substantial, amounting to millions of dollars a year. Payments in lieu of taxes which some municipalities might have to make would amount to considerably less than the taxes presently paid by the utilities.

The utilities simply feel that it is in the public interest for them to continue to own and operate their hydro plants. The numbers speak for themselves. Of the 94 million electric customers in the United States, utilities serve 72 million (77 percent) of them, whereas the municipal systems serve relatively fewer electric customers. The utilities that seek to relicense their 11 hydro projects now subject to competitive applications, for example, serve over 8.4 million customers; the competing municipalities serve only 836,000.

Furthermore, if the utilities lose the 11 hydro plants currently in competition to the municipalities, the average fuel cost for the electricity generated by the utility will go up automatically. This will cause an immediate increase in the electric rates for the customers of those utilities of $170 million a year. (This figure is based on 1981 generation and expressed in 1981 dollars.)

Nationally, utilities' hydro plants generated approximately 61.7 billion kilowatt hours in 1981. To produce the same amount of electricity using oil would require 105 million barrels at a cost of $3.5 billion. For the millions of residential, commercial, industrial, and agricultural customers served by the utilities with hydro plants, the equivalent of between $1 billion and $3.5 billion in fuel costs, depending on the substitute fuel(s), is saved each year.

Additional costs to be borne by utilities' customers are likely to follow. Replacing electricity generated by the lost hydro projects may require some utilities to purchase more expensive replacement power from another utility. The generating capacity represented by the lost hydro project may have to be replaced by purchasing an interest in the generating plant of another utility. New generating plants ultimately may have to be constructed sooner than otherwise anticipated to meet increases in demand for electricity. One utility which is threatened with the loss of a hydro project—Pacific Power and Light's Merwin Project—estimates it would cost $731.7 million to replace the project with a 161 Mw coal-fired steam plant.

Utilities know that their investment in hydro plants in the twenties and thirties, and paid for over the years by their customers, is now a key component of their generating capacity. Hydro projects are particularly valuable in allowing these utilities to achieve minute-by-minute changes in electrical output inexpensively in order to accommodate hourly changes in customer demand for electricity. Most of the utilities' hydro plants, even those built 50 or more years ago, are in excellent condition. These plants can be expected to provide efficient service to many generations of people to come.

If the utilities' hydro projects are lost to municipalities, so also are the taxes the utilities pay on the projects. Counties and municipalities, if they are to maintain the same level of services, would have to replace many millions of dollars that they presently receive in tax revenues from utilities. For decades, counties and municipalities have used the tax revenues received from utilities' hydro projects to support local school systems, construct and maintain roads, and provide other essential government services.

According to a report prepared by the Edison Electric Institute,* examples of the taxes that utilities pay include a Maine utility that paid $2.3 million in state and local taxes on 6 hydro projects; these projects are up for relicensing by the end of 1993. For the years 1977–1981, New York State's Niagara Mohawk Power Corporation paid over $21 million in taxes on 14 hydro projects, also up for relicensing by the end of 1993. In the Southeast, Alabama Power Company in 1981 paid over $2 million in property taxes on its hydroelectric facilities; most of this tax revenue goes to county governments.

Removing hydroelectric properties from local tax rolls could force local governments to increase tax rates for other property or to look for other sources to replace the lost revenue. Niagara Mohawk facilities, for instance, account for 72 percent of the assessed value in the Town of Colton, 74 percent in the Town of Parishville, 88 percent in the Town of Orwell, and 43 percent in the Town of Pierreport. In 1982, Alabama Power Company's total property tax assessment was approximately 35 percent of the total assessed property value for Randolph County in which its R. L. Harris hydro project is located.

Ultimately, if utilities lose their hydro projects to municipalities, the utilities' millions of customers will not only pay higher rates for their electricity, they may also have to pay increased property and other local taxes to make up for lost state and local tax revenues. A dual injustice would result.

Surely, the utilities argue, none of these potential results can be in the public interest.

Ultimately, if utilities lose their hydro projects to municipalities, the utilities' millions of customers will not only pay higher rates for their electricity, they may also have to pay increased property and other local taxes to make up for lost state and local tax revenues.

What's Next?

Utilities have operated their hydro projects in the public interest and for the benefit of their customers for many years. But the relicensing of these projects under the Federal Power Act as now interpreted no longer reflects sound public policy. Congress needs to reverse the FERC's 1980 interpretation in order to safeguard the public interest.

Congress can accomplish this by a simple but straightforward amendment to the Federal Power Act. The amendment should establish what is in effect a rebuttable presumption in favor of the existing licensee upon relicensing, provided it is willing and able to meet the licensing standards embraced in Section 10(a) of the Federal Power Act. If the existing licensee's project is "best adapted to a comprehensive plan for improving or developing a waterway or waterways for the use or benefit of interstate or foreign commerce, for the improvement and utilitization of water power development, and for other beneficial public uses, including recreational purposes" it would be entitled to a new license. Only if the existing licensee did not commit to such a plan should a new license be subject to competition from other applicants. ☐

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Energy Strategies For California's Future

By Mason Willrich

For both the state and the nation, tomorrow depends on the innovation and cooperation of business and government today

Local governments as well as the energy utilities have major roles to play in determining the energy future of the state of California, the West, and ultimately, the United States.

I would like to examine our energy future, here, focusing on three fundamental points.

First, energy strategies, including those developed at a local level, must be considered in a global context, or framework.

Second, the future we confront is fraught with uncertainty, and therefore, systematic planning, that incorporates options for dealing with a variety of contingencies, is essential.

And third, local governments and energy utilities must work effectively together to assure the availability of energy services to support the kind of economic growth and social development in local communities that the people hope for.

Global Framework

The global framework in which energy issues are embedded has several dimensions. Prior to the 1970s, most people took energy for granted. We were blissfully unaware of the dependence of every aspect of our advanced industrial society on a continuous flow of energy. Then, in 1973–74, the Arab oil embargo and OPEC oil price shock awakened us to the realities of our dependence.

We now fully realize—as we drive to the gasoline pump—that the fuel we purchase there is supplied from a world oil market and that the oil heartland lies in the Persian/Arabian gulf, one of the world's most politically volatile regions. The price we pay for gasoline, and whether supplies are ample or whether we have to wait in line, depends in large measure on the political security and crude oil production policies of the Saudi Arabian kingdom.

Natural gas is another illustration of our international energy interdependence. While much of the gas we use in California comes from the southwestern United States, a sizable share is imported from Canada and small amounts from Mexico. Furthermore, natural gas prices are influenced greatly by oil prices, and the gas supply network has intercontinental dimensions in North America, Europe, and Asia.

Energy is also a subject where international cooperation and organization are essential. The International Atomic Energy Agency in Vienna is a global organization that promotes the wider use of nuclear power and plays a vital role in verifying, through unprecedented international inspection, that materials and equipment intended for peaceful nuclear activities are not diverted to any military purpose. The International Energy Agency in Paris is an organization that coordinates the energy policies of the industrially advanced countries and also administers novel and important arrangements for international sharing of oil supplies in the event of a future world oil supply emergency.

Energy is simply a dramatic illustration of the interdependence and mutual vulnerability of the world community of nations as well as an example of the necessity for cooperation among all levels of government. For most of us, isolation, or energy independence, nationally or locally, is not a viable alternative.

A second dimension of this global framework is in the pervasive role that energy plays in every local economy and society.

Mason Willrich is Vice President, Corporate Planning, for Pacific Gas and Electric Company. This article grew out of a speech he made earlier this year at the League of California Cities conference on Energy Strategies for Local Government.

Pictured opposite, view of downtown Los Angeles.

In almost every human activity, whether at home, work, or play, we use some form of energy supplied from an external source. The price, therefore, as well as the availability of energy, must be weighed (consciously and carefully), in every major decision.

One of the most troublesome aspects of the global energy framework is the relatively short amount of time available to define and implement strategies.

In the United States, real energy prices (that is, energy prices with the effects of general inflation removed) declined during the 1950s and 1960s. During the 1970s, crude oil and gasoline prices shot up, while increases in natural gas and electricity lagged, largely because of government price regulation. These national trends were true for California as well, which had benefited from an abundant supply of hydroelectric power in the 1930s and 1940s, and new supplies of natural gas and oil in the 1950s and 1960s.

The prices we pay for energy services must be related to long-term incremental costs if we are to make the proper decisions about energy consumption. We also must bear in mind that the price for energy paid by consumers is not the full social cost. Energy production and consumption are sources of environmental pollution, and many energy consuming activities can pose dangers to the public health and safety, automobile driving being the most vivid example.

One of the most troublesome aspects of the global energy framework is the relatively short amount of time available to define and implement strategies. Enormous changes in the structure of energy demand and supply have occurred in the past. In less than 200 years, societies in the forefront of economic advance have made two major transitions, from wood to coal in the 19th century, and from coal to petroleum in the 20th century. And throughout the 20th century, there has been a persistent trend toward conversion of an ever-increasing fraction of energy resources into electricity for final use. While in the grand sweep of human history such changes appear very rapid, from the viewpoint of the present, they appear slow indeed.

The OPEC oil price jumps during the 1970s, following the Arab-Israeli war and the Iranian revolution, signalled the end of an era of cheap oil and the necessity for a major transition to much higher-cost alternative energy resources. But the jumps were too high and the world economy has fallen flat.

Largely as a result of the worldwide economic slump, oil prices are momentarily declining and supplies are plentiful, at least until OPEC once again reaches an agreement. Regrettably, many efforts to develop long-term alternative supplies and technologies, based upon their value as replacements for an exorbitantly priced oil supply, have collapsed. Nevertheless, major structural changes are under way in the residential, commercial, and industrial markets for energy services.

In energy affairs, time is disjointed. A major energy supply project may take 10–15 years from conception to operation and have an operating life of 35–40 years. These time periods for implementing major energy projects are substantially longer than the two- to six-year periods that dominate political decision-making or the one-year or even quarterly earnings periods that often apply to business decisions.

Thus, perhaps the most difficult aspect of the energy problem is finding how to develop and successfully implement long-term energy plans and projects in an era in which politics and business alike are preoccupied with the short-run. For it is the long-term solution, and not the quick fix, that we must seek.

Energy Strategies

Given the framework I have outlined, for what kind of future should we plan? What are the essential elements of a successful energy strategy for coping with the overall environment that we foresee? Let me address each of these questions briefly, answering from the perspective of the energy utilities.

The future, of course, has been and always will be unknowable. But as we now look ahead from the vantage point of 1983, we may well feel overwhelmed, if not paralyzed, by uncertainty. It is instructive to contrast our current sense of the future with how we felt just 10 years ago about the decade ahead.

In the early 1970s the signs of immediate trouble went unheeded. Government and the energy industry were planning for more of the same: a continuation of the rapid economic growth and abundance of cheap energy resources that had characterized the 1950s and 1960s. In the early 1970s, we did not foresee the OPEC oil price shocks, the hyperinflation and stagnation of the world economy, the volatility of the capital markets that dominated the remainder of the 1970s and early 1980s, nor did we foresee Three Mile Island in 1979, which shook the foundations of the nuclear power industry. In the early 1970s, we were confident about our ability to foresee the future and optimistic in our planning assumptions.

What lessons should we draw from the painful experiences of the previous decade as we look ahead? I believe we should now approach the future with considerable humility and a little skepticism.

First, we should plan for much slower growth in demand for electricity and gas in the next decade than in the 1950s and 1960s, and slower growth even than in the 1970s.

Government price regulation has tended to insulate the markets for electricity and gas from the oil price shocks experienced during the 1970s, so that the full consumer response to higher prices will be felt first during the rest of the 1980s. Furthermore, while economic recession accounts for a large part of the recent decline in demand growth, structural changes in end-use markets also account for a large part. The relative proportions of the decline accounted for by each factor are as yet unknown.

But what if we are wrong about this aspect of the future?

Then we must be prepared on a contingency basis to move ahead with supply options with relatively short leadtimes. Fortunately, there are a number of options that appear promising, including increased conservation and load management, cogeneration, and small-scale alternative energy development, as well as increased coordination of energy supplies on a regional basis.

Second, we should plan on continued volatility in the market prices of key supplies for the energy utilities. Oil prices could collapse or they could explode again. The present world oil glut creates a dangerous illusion of a stable market. Natural gas prices either could spike after deregulation in 1985, or stay competitive with oil. It is by no means clear that deregulation of wellhead prices would produce major natural gas price increases. And future shortages are more likely if price controls are continued beyond the schedule presently embodied in federal legislation. Electricity prices are likely to follow diverse regional patterns. In California they will remain quite sensitive to weather, to natural gas prices, to the availability of hydropower, and to the availability of low-cost electricity purchases from outside the state.

The energy utilities, like other capital-intensive members of the economy, will be hit especially hard by wide swings in the costs of money. Such swings appear more likely than not in the face of the huge U.S. government budget deficits presently projected and the expectations of rekindled inflation induced by those deficits. If we are wrong with respect to our assumption about volatility, we can simply be thankful that coping will be that much easier.

The energy utilities, like other capital-intensive members of the economy, will be hit especially hard by wide swings in the costs of money.

Third, we should expect continued, and perhaps even stronger, consumer resistance to higher prices for electricity and gas services. The public tends to view big oil companies and big utilities with suspicion. But from the consumers' viewpoint, there is one fundamental difference between a large oil company and an energy utility. The consumer can shop around for gasoline and compare prices. But, with rare exceptions, he or she cannot do so for electricity and gas.

Given a planning environment for energy utilities that is characterized by relatively stagnant product demand, volatile input prices, including the price of borrowed money, and unrelenting consumer pressure to minimize price increases, what are the essential elements of a strategy for coping?

I believe such a strategy should be composed of three main elements.

The first element is to increase the ef-

During the remainder of the 1980s, I believe the utilities must move beyond rudimentary concepts of conservation and load management into the realm of energy management services.

ficiency of energy utility operations. During the 1950s and 1960s, while the economy was growing rapidly, growth in demand combined with technological changes in bulk power generation and transmission produced declining costs in the electricity supply business. Government price restraints on wellhead prices and advances in gas pipeline technology led to a comparable decline in retail natural gas prices. So the paramount concern became construction. Utility system growth was good for utility ratepayers and shareholders alike. During the 1970s and early 1980s, the electric utilities then became preoccupied with completing their construction programs, often cutting back in light of reduced demand growth. The gas utilities, on the other hand, were driven to scramble for reserves—some of which were tied up by long-term contracts at very high prices—by the immediate threat of supply shortages.

During the coming decade, however, many energy utilities will become primarily operating companies, deferring new construction of large supply facilities until the 1990s. Attention, therefore, must focus upon increasing the efficiency and productivity of all phases of utility operations. A well-managed energy utility should have the following attributes:

- a work force that is dedicated, skilled, innovative, and flexible;
- an organization that is adaptable and capable of participating effectively in a wide variety of projects involving a multiplicity of participants and novel technologies; and
- a paramount concern with customer service and the provision of reliable and high quality service at the least cost to the customer.

This shift in focus, from building new plants and acquiring new sources of energy to wringing productivity gains from the operation of existing facilities, is an important one for the energy utilities. However, this redirection must not preclude meaningful planning for additional resources which will be needed in the 1990s.

The second element of an effective energy utility strategy in the coming decade is to increase regional and interregional coordination and cooperation. This cooperation is especially important in the western United States with regard to electric power generation and long-distance transmission. At present, utility operations tend to be artificially constrained by the political boundaries of states.

As an integral part of increasing the efficiency and productivity of operations within their respective service territories, electric utilities must assure that electricity is generated and transmitted in the most economical manner throughout an entire multistate region. Moreover, the formation of regional generation companies should be considered as one way of providing for safe and efficient construction and operation of future nuclear and coal power plants.

The third element of strategy must be to transform our relations with our customers. During the 1950s and 1960s, utilities actively marketed their product. Sometimes, as in the case of the all-electric home, it was a pretty hard sell. During the 1970s, a turn toward conservation occurred. The energy utilities, some pushed by regulatory agencies and some quite willingly, found themselves in the baffling business of trying to sell less rather than more.

During the remainder of the 1980s, I believe the utilities must move beyond rudimentary concepts of conservation and load management into the realm of energy management services. All customers must become efficient energy managers. Before a utility adds new electric generating plants and supplemental gas supplies, it should be assured that all cost-effective energy savings have been realized.

We must do more than offer audits and subsidized loans to finance conservation measures. We should develop means for the widespread provision of analytical services and information technology pertaining to the use of electricity and gas by all classes of customers within a utility's service area. This strategy should be designed to penetrate well within end-use markets for energy. Existing regulatory barriers to such an active role for the utilities as energy management and service companies should be removed.

A strategy composed of the elements I have outlined will enable an energy utility, operating in an environment of increasing costs, to maintain its vital role in the infrastructure of social and economic development in its service territory.

Local Governments

In conclusion, let me address the relationship of cities and local governments to the energy utilities. As you know, some localities have their own electric utilities while others are provided electricity by investor-owned utilities. With rare exceptions, gas service is provided by investor-owned utilities throughout the state.

The issue of public versus private power has a long and controversial history which I do not propose to cover. Rather, taking things as they are, where do we go from here?

First, local communities and the utilities serving them have a common interest in developing and implementing a long-term, least-cost energy strategy for the provision of electric, gas, and conservation services.

Unfortunately, the costs of electric and gas service will continue to increase in the future because of the shifting resource and technological foundations of the industry. The primary task of the energy utility is to minimize future price increases while maintaining reliable services.

But we all recognize that the future is dominated by uncertainty and that, in choosing an energy strategy, we are faced with a multiplicity of interrelated decisions, each with a highly uncertain outcome. In such circumstances, and given the importance of the matter to the common welfare, we should search continually for ways that the utilities and local governments can work together as we implement long-term plans within the framework of energy policies.

Second, local communities and the utilities have a common interest in the successful implementation of cost-effective energy conservation programs. Local governments can and should set an example for their citizens in handling their own energy use. Further, local governments and the energy utilities should review systematically all the ways in which they can aid each other in implementing conservation programs in residential, commercial, and industrial markets.

I believe local government advocacy and leadership can be a great help to the energy utilities in assuring the success of cost-effective conservation programs. One example is the Community Electric Management Program to reduce summer peak electricity usage, which has been notably successful in at least half a dozen cities.

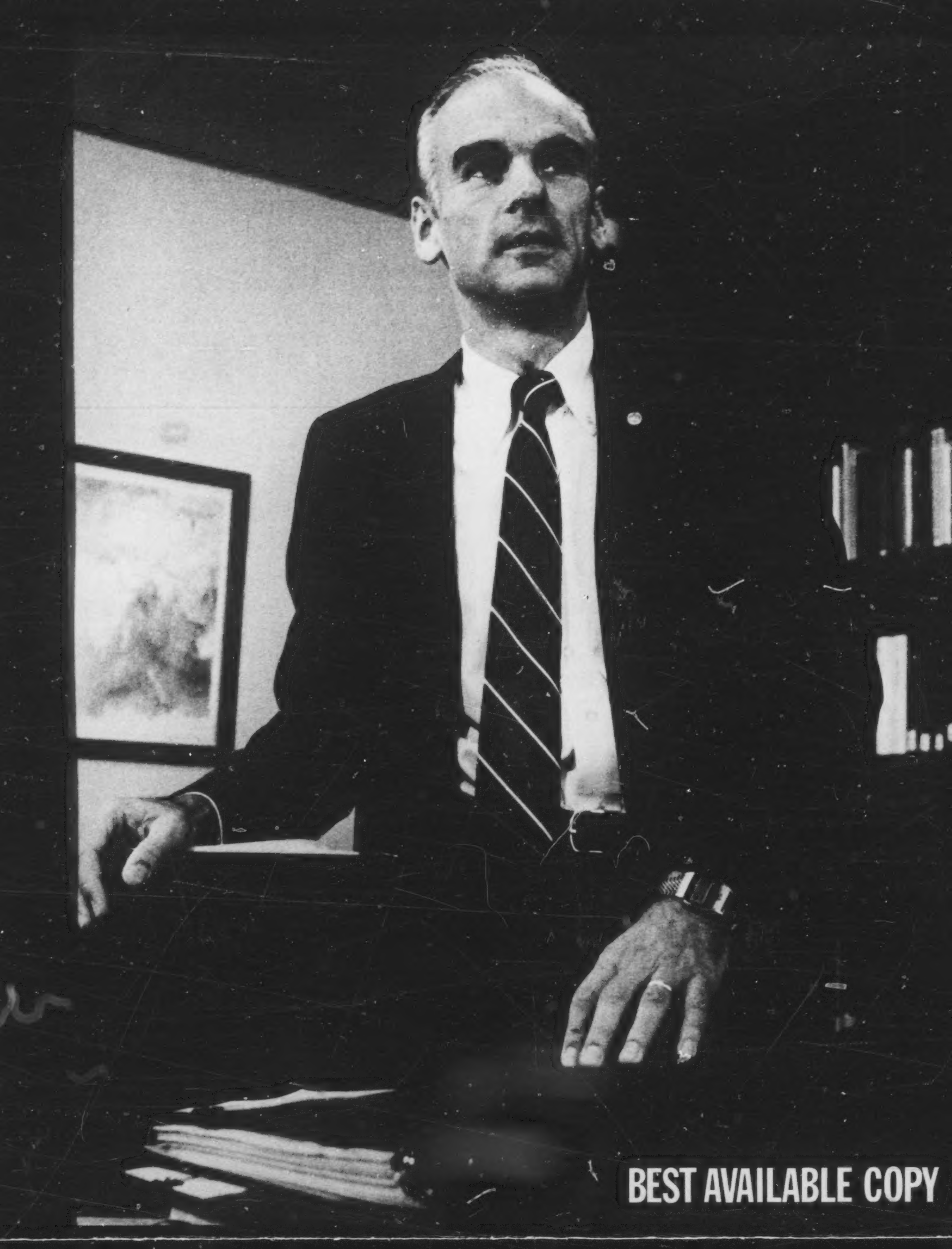
Third, despite our efforts to minimize price increases and to save through conservation, we must be sensitive and respond to the needs of those who cannot afford to pay their utility bills. The long-term answer to this problem is to restore America's economic vitality and achieve full employment. But in the meantime, we must help those who cannot presently afford to pay for energy services that are essential.

The California utilities already have adopted programs to provide such assistance. But the needs are much greater than utility-sponsored programs alone can cover. Here is another area in which I believe utilities and local governments must broaden and intensify their work together.

Considering the Long-Term

Finally, let us consider the long-term future. That future need not be energy limited. Moreover, innovation with new energy supply technologies can provide the cutting edge of the process of revitalizing and modernizing the American economy—a process that has paramount importance, not only for our welfare and security as a nation, but for the hopes and needs of people everywhere for a growing and open world economy. □

. . . we all recognize that the future is dominated by uncertainty and that, in choosing an energy strategy, we are faced with a multiplicity of interrelated decisions, each with a highly uncertain outcome.



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An Adequate Supply At A Reasonable Rate

Energy Secretary Donald Hodel addresses the investor-owned electric utility industry

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Donald Paul Hodel is the fourth United States Secretary of Energy, previously having served as President Reagan's Under Secretary of the Interior. Hodel was appointed Deputy Secretary of the Bonneville Power Administration in 1969 and its Administrator in 1972. He was active in both corporate and private law practice in Portland, Oregon, for nine years, and served for two years as the President of the National Electric Reliability Council, as well as on its board of trustees.

Hodel has also served on the board of directors of the Electric Power Research Institute, the executive committee of the Western Systems Coordinating Council, the advisory committee on energy facility siting of the National Science Foundation, and the board of directors of the U.S. National Committee of the World Energy Conference. He received his B.A. in government from Harvard University and his J.D. from the University of Oregon School of Law.

On a National Energy Policy. There are those who suggest that the United States of America doesn't have an energy policy. They're wrong. We do have an energy policy. And like any good policy, it has a goal, with strategies and programs to reach that goal.

The goal of America's energy policy has been for a long time, if we would have chosen to articulate it in these terms, that as a nation we want to have an adequate supply of energy at a reasonable price—pretty simplistic goal.

The strategies by which we seek to achieve this goal, however, have varied from Administration to Administration and from Secretary to Secretary. The first strategy we favor in this Administration is a reduction of federal government intervention in the energy business. Relying on the market place and the decisions of industries provides a far better means of assuring an adequate supply of energy at a reasonable price over an extended period of time than any combination of governmental intervention could.

Another strategy which we favor is that we need to have a balanced, mixed energy system in this country. No other approach could truly be considered rational, any more than an investment portfolio consisting of only one stock or one bond, or a diet consisting of only one food category, would be considered a balanced or rational investment program or diet. So, too, in energy strategies, a balanced, mixed energy system is the only rational approach.

On the Decontrol of Natural Gas. I've been engaged substantially, since I came to the Department, in an effort to decontrol the price of natural gas at the wellhead. I liken decontrol of the natural gas market, when people challenge the concept as somehow unworkable, to the regulation of electric utilities, which is generally well understood. Although the electric utilities are regulated, the government does not regulate the price of most of their fuels. If we can get natural gas decontrolled, I'm convinced that we will see an increased supply and a reduced price. And if in conjunction with that we can get rid of the Fuel Use Act, and Incremental Pricing, we will have made a major contribution to the benefit of the energy programs in this country.

On Nuclear Power. Nuclear licensing reform is on our agenda. After 29 years of operation of the regulatory process affecting nuclear licensing and operation in this country, we have perhaps learned enough to make some suggested changes—changes which will improve the process, provide more adequate safety and public participa-

Secretary Hodel, pictured opposite, spoke to the investor-owned electric utility industry at the Edison Electric Institute's 51st annual convention in June. This article presents excerpts of his remarks.

tion, and provide a means of completing projects undertaken on a far more reasonable, rational time schedule.

We are also carrying on an active effort to implement the Nuclear Waste Disposal Act passed in the lame duck session of the 97th Congress. This is a very difficult thing to do, because the bill, as it was passed, contained a number of competing provisions which require substantial interpretation. But I believe we are going to make the grade with that bill. I think it represents the solution to the problem of nuclear waste disposal, and will make the argument in opposition to nuclear power plants no longer valid.

On Research and Development. We have a large role in research and development—science and technology—at the Department of Energy. And this role will continue. The national laboratories in this country represent a $25 billion investment over a 40-year period by the American people in their desire to keep this nation in the forefront of technology. This Administration, even at the time of a deficit, which is of great concern, has proposed increases in commitment to science and technology, to research, and to the national laboratories.

In the area of energy conservation, we are carrying on research programs which we believe will contribute to the furtherance of the ability of the private and commercial sectors to bring improvements into the marketplace. We're working on more efficient engines. We're doing research on batteries. And we are working on appliance standards.

In the area of renewables, we are pursuing wind, ocean-thermal, and geothermal energy conversion. With regard to solar power, we've participated in the development of central station solar collectors. We're doing research on photovoltaics. One of the things that's overlooked in this country is that today, in terms of dollars spent, between one-half and two-thirds of the research on solar-photovoltaics is being carried on in the non-federal sector. I think this is a great achievement, and it's beneficial. Some of the most current and exciting developments have been occurring in that non-federal sector.

In the area of fossil fuels, we're investing in clean coal technologies to remove sulphur and ash in a more efficient, less costly way. We're also carrying on research with regard to magnetohydrodynamics (MHD).

We do not, however, believe that it is the role of the federal government to move further into the demonstration stage. Let me explain why.

Our preference is to deal with research and proof of principle. When it comes to the building of a pilot project to demonstrate the feasibility of a technology, we find that if the federal government builds the project, we put so many bells and whistles on it that by the time we're ready to turn over to the private sector for general application, the private sector can't afford to build the project and make it operable. It seems to us then that our role should be in basic research, and proof of principle. And that when the private sector sees the opportunity to invest in a resource, and make it generally available, that is when it should be done.

For nuclear energy, we're carrying on

Hodel testifying at his Senate confirmation hearing in December, 1982.

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health and safety research. We're participating from a research standpoint in the cleanup of Three Mile Island. And we are attempting to find ways to continue the Clinch River Breeder Reactor, which is, in fact, a demonstration project, and counters precisely what I was just saying about MHD.

Let me point out that one of the problems we're having with the Congress of the United States today is in the fact that the Congress is concerned that federal costs have gone up too high. If we're to continue the Clinch River project, it's going to be necessary that we find additional funding from outside the federal sector.

From the standpoint of programs which support our national energy policy, an important element is communications. In the area of technology transfer, I do not believe we are doing a good job. I don't think my predecessors have done a good job. I don't fault them for that, any more than I currently fault myself.

Finding a way to move research, even promising research, to the area where it becomes commercially available is extremely difficult and has been slow, slower than perhaps is desirable. We are going to continue to work on this. It's my desire, and when I have an Undersecretary of the Department, he will be largely responsible for working on that subject.

On Hydroelectric Power Plant Relicensing. With my background at the Bonneville Power Administration, it may not be surprising to know that I have always supported the preference clause given to states and municipalities in licensing of hydroelectric generating projects. (Editor's note: For a more detailed discussion of this subject, see the article on page 3.) I have always felt that the amount of power involved was such that it historically has not enormously distorted the licensing process. I have also felt that the political price to be paid to affect the preference clause was far too high for us to become engaged in trying to do so. So I've supported it. But I don't support its extension beyond its appropriate role.

Today, as fifty-year licenses terminate on existing hydroelectric generating facilities, public power agencies have filed applications to be given pref-

Wide World Photos

Hodel with President Reagan, and members of the Cabinet and Congress at signing of the Atomic Energy Amendments Act bill.

erence for licenses to own and operate those projects. I think those filings are destructive for the industry. When I spoke to the American Public Power Association recently, I had the same message for them.

It seems to me that we are creating a situation which nobody can control, and which may not be in the best interests—will not, in my estimation, be in the best interests—of this industry.

Not in retaliation, but as a natural outgrowth of the kinds of filings that have taken place for investor-owned generating facilities by public systems, we now have at least one filing from an investor-owned utility requesting power from federal facilities presently under the preference clause. I'm advised that it's a very well written, very well documented brief. And it certainly does not appear to be frivolously filed. I could anticipate that with a negative reaction to that filing, litigation will ensue.

I don't think the courts are equipped to resolve this issue in a timely fashion. And somebody, or somebodies, will undoubtedly produce legislative fixes which may or may not in fact be fixes.

Hodel answers questions from workers on the economic and political considerations of energy development.

Wide World Photos

What troubles me about this issue is that for the amount of generation involved—a very small fraction, probably between ten and fifteen gigawatts of generating capacity, perhaps a bit more, but not much—we very much jeopardize the unity of this industry in such a way that it will continue to be a sitting duck for the critics who seek nobody's best interests in the long run. I hope that the industry can work to develop positions and solutions to this problem. I simply do not know how the industry can get a handle on it at this stage, but I am terribly concerned about its long-term impact on the industry and its public credibility.

On Customer Relations. Any time you increase prices for people, they're going to be suspicious of you. They will welcome hearing from a critic who gives simple, straight-forward solutions to problems, regardless of their merit. You can spend six months researching an issue carefully, go out with a carefully planned presentation and factually lay out all of the issues, and what you believe to be the solutions. And, as I have kiddingly said, a freshman at the local community college can take an envelope and scribble a few notes and make a calculation about the nearness of the sun to the moon and a few other things, and get equal coverage in the local papers. That makes it difficult for your credibility.

There are things that the investor-owned electric utility industry, or much of it, is doing that help with regard to customer relations. Activities related to conservation and alternative energy sources, I believe, contribute significantly to the public acceptance of what the industry is doing. Its credibility improves, I think, as it invests in solar, wind, and geothermal energy conversion. There are imaginative programs afoot in the country today which utilities are contributing to and supporting on a proper basis, such as the installation of insulation. Such programs contribute to credibility with the public, and increase the industry's ability to have a positive influence on society's thinking about energy.

I would urge the industry to seek and to continue to seek ways in which it can be a comprehensive energy supplier to households. I especially think in terms of conservation and solar-type units when I say that. When I was at Bonneville Power Administration I was struck by the fact that we would leave to the residential consumer the decision as to whether or not to install certain kinds of alternate energy devices. These devices represent perhaps one or two percent of a system's load, making no real difference.

But consider the impact on a utility system if a significant share of its load, say 10 to even 25 percent, becomes residentially owned and controlled, as it might with solar systems, for instance. The investor-owned utility increasingly becomes a peaking resource. And I submit that the financial implications of that are such that it will drive the utility into a very difficult situation. It seems to me the industry needs to be finding ways to be a comprehensive supplier.

On the Nation's Energy Future. This nation is dependent upon energy. It has been built up by energy. Clearly, we need the kind of leadership which the electric utilities can provide in the area of electric energy.

One of the arguments I make about the importance of the diversified system we have is that because it is diversified, because there are so many different capable people making different decisions, sometimes on the same issues, we get the benefits of flexibility in this system, benefits unlike anything that can be imagined in a system where some energy czar, or Secretary of Energy, or whoever, is making broad, national commitments, and binding decisions with regard to the supply of energy.

I think that as the industry reacts to the facts as it sees them, and as it sees them change, it will help this nation move toward a rational energy policy. This is the greatest industrial nation in the world. It is the cornerstone of the military security of the free world. And the United States of America is what it is today partly because it has had the best and the most reliable and the least-cost electric system anywhere in the whole world. □

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Environmental Negotiation

By Peter J. Ognibene

Solving disputes by discussion, rather than by litigation, is a promising trend, often providing solutions that everybody involved can live with

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When industries, environmentalists, and government regulators communicate with one another, it is often through their attorneys. A process referred to generally as "environmental negotiation" is beginning to change this, and though no panacea, it provides a more flexible approach that can lead to the solution of a broad range of environmental disputes.

Finding our way to the bargaining table instead of the courtroom will not be easy. Our adversarial system traces its lineage to medieval England, when "trial by ordeal" and "trial by combat" were the norm. While the combatants nowadays no longer wear armor, the competition in the courtroom is no less vigorous, though (mercifully) less sanguinary.

Unfortunately, today's disputes lack the simplicity of two serfs claiming the same cow. While many environmental regulations contain seemingly precise standards, the scientific data behind the numbers are often incomplete or conflicting and, at times, overlooked by regulators caught up in the give-and-take of compromise.

Litigation of environmental regulations then becomes not only time-consuming and costly, but often inconclusive. Even when a judge does issue a decision, it may provide little more than a starting point for yet another round of legal jousting.

We Must Be Adversaries

"The system says we must be adversaries," remarked Irving Shapiro, the former Chairman of the Dupont Company. "You've got single-issue groups on one side pressing the agency, you've got people in the agency pressing for their viewpoint, you've got people in the industry pressing for their viewpoints, and each one is shooting at the other. Ultimately, you wind up in court and then work out the compromises. . . . You have to go through all that agony to do something that you should have been able to do at the beginning."

Environmental negotiation will not work in every instance. Proponents and opponents of the Clinch River Breeder Reactor, for example, would find little in common. Their positions are unequivocal: one side wants it built; the other wants to stop it.

"Mediation does not lead to a resolution of the basic differences that separate the parties in conflict," said Gerald W. Cormick, the Executive Director of the Institute for Environmental Mediation in Seattle. "Rather, in situations where no party perceives that it is able to gain its goals unilaterally but that it must deal with some other entity, mediation can help them agree on how to make accommodations that enable them to coexist despite their continued differences."

In wage disputes, labor and management routinely engage in collective bargaining. A successful strike does not destroy a company; it wins greater benefits for workers. Similarly, in environmental controversies in which neither side is out to destroy the other, it may be possible to work jointly toward an accord.

Mediators normally become involved in contract talks when labor and management reach an impasse. "In an environmental dispute," said Gail Bingham, an Associate of the Conservation Foundation, "the mediator does not enter after negotiations have begun and gotten stuck. Quite to the contrary, the mediator enters before any negotiations are even begun."

According to Bingham, environmental negotiations have produced about 40 agreements over the past decade and

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Ross Dam, pictured opposite, the subject of a dispute between Seattle and British Columbia which ended in a signed, 80-year agreement.

". . . A negotiation is aimed at an objective of agreement among the parties. So, it hands back to them the power to decide. That, in itself, goes a very long way if the parties need a decision, which they very frequently do."

defused another 40 controversies with "some kind of innovative approach [where] the end product was not a written, signed document of settlement. It may have been improved information-sharing or the formation of a committee to monitor the conflict."

Not every environmental controversy lends itself to mediation by a neutral third party. Before negotiations can begin, Bingham remarked in an interview, the people involved need to answer a number of basic questions: "Can we identify all the parties to this dispute? Who has an interest at stake? Is that interest organized into an entity with enough internal cohesion to have a representative who can bargain for that entity? Do each of those parties agree that negotiations are in their interest? Can all the parties agree on the scope of issues to be negotiated? Can they agree on how an agreement, if reached, would be implemented?"

For the individuals who must answer those questions, Bingham stressed, "the key is getting clarity." In our adversarial system, that is sometimes easier said than done.

To sell their case to judges, legislators, or administrators, organizations, as a matter of strategy, often make extreme representations of supposedly factual data and concoct doomsday scenarios. "It's often the case," Bingham observed, "that when people are stating their positions very strongly it's to influence a decision maker. But in negotiations, the dynamics change fundamentally because the parties *are* the decision makers. A negotiation is aimed at an objective of agreement among the parties. So, it hands back to them the power to decide. That, in itself, goes a very long way if the parties need a decision, which they very frequently do."

Finding Common Ground

According to William Humm of the New England Environmental Mediation Center, though mediators do not

Making Up the Rules

Lawmaking does not end when the President signs a congressional enactment. Indeed, for the people most directly affected, that step is just the start of a process that leads to more explicit rules.

Although the federal government solicits public comments when it proposes new regulations, insiders are ultimately responsible for the content of the final rules. With intentional understatement, Joseph A. Cannon, Associate Administrator of the Environmental Protection Agency (EPA), acknowledged that the "process is less than perfect." In fact, he added, "rule-making is marked frequently by delay, high cost, uncertainty, and litigation. . . . Our conviction is that there must be a better way. We believe that negotiating the content of a regulation has the potential to produce substantially superior rules, acceptable to a wide range of interests, more quickly and without the need for litigation."

To test that proposition, EPA recently launched a "regulatory negotiation project." According to the agency's notice in the *Federal Register,* "for two selected rules, the project will use face-to-face negotiations among interested parties in place of EPA's usual regulation development process."

Responding to EPA's request for recommendations, John J. Kearney, Senior Vice President of the Edison Electric Institute, suggested that "the rule or rules chosen for regulatory negotiation *not* be politically controversial. Where the rules are highly controversial, the parties are more likely to take more extreme positions and compromise becomes unlikely. Where the rules involve technical issues—*e.g.,* the standards of performance that certain control equipment can meet—they may be better suited for negotiation." (As we went to press, EPA officials had yet to announce which rule or rules would be negotiated.)

In an interview, Philip J. Harter, a Washington attorney well-versed in regulatory matters, said that the push for negotiated rule-making has come mainly from "clients who are objecting mightily to the enormous costs of litigation."

take sides, they often spend more time with the negotiators separately than collectively. "We almost always meet individually with the parties before a joint meeting," said Humm. "We do a lot of our work in those individual sessions, in part to hear from the individual parties what they are most concerned about . . . but also to alert them to what they are likely to hear from their adversaries at the upcoming meeting. What we try to do is have no surprises at the joint meeting."

When asked if there is a danger the mediator might take control away from the parties, Humm laughed. "By and large," he replied, "they strongly resist being led. They have a much clearer sense of what they can swallow than we do. They also have a much stronger and deeper knowledge and understanding of the issues than we do. We don't presume to be engineers, finance experts, or ratemaking specialists. What we are trying to do is help them find some common ground with their opponents. Often that requires us to reveal our ignorance and to be told why such-and-such a thing won't work."

In the pressure cooker of negotiations, participants may become so embroiled in the process that they lose touch with the company, group, or agency whose interest they represent. When that happens, they may find their toughest job will be winning support for a proposed settlement within their own organizations.

"We're always very much concerned that a given representative not get out in front of what he's likely to be able to sell to his constituents, whether it's an informal organization or a company," said Humm. "We really don't want to get people in that kind of posture. It's bad for them, and it's bad for the process."

Opportunities Through Conflict

"Conflict, when it arises from different sets of values and from competing interests, is inherent in environmental

In the pressure cooker of negotiations, participants may become so embroiled in the process that they lose touch with the company, group, or agency whose interest they represent. When that happens, they may find their toughest job will be winning support for a proposed settlement within their own organizations.

Time is also a factor. "Once people really dedicate themselves to the negotiating process," said Harter, "it takes six to nine months. Rule-making almost always takes a couple of years."

President Franklin D. Roosevelt, himself a lawyer, once observed that "a large part of the legal profession has never reconciled itself to the existence of the administrative tribunal. Many of them prefer the stately ritual of the courts, in which lawyers play the speaking parts, to the simple procedure of administrative hearings which a client can understand and even participate in." Some believe that attitude has not changed very much in four decades.

Instead of routinely assigning regulatory matters to their lawyers, interested parties may prefer to take a more direct role in negotiating the rules under which they will have to operate. Harter believes some members of the bar may resist that sort of a move.

"The adversarial process breeds specialists whose expertise is the process itself," he said. These "intermediaries sell conflict, which in turn exacerbates the problems of the adversarial process. Not only does an intermediary have little incentive to minimize conflict, he usually lacks the substantive ability and authority to make tradeoffs with the opposing participants."

With negotiated rule-making, he added, "the regulation's legitimacy would lie in the overall agreement of the parties. Thus, the only facts that must be included in the preamble to a negotiated regulation are those that the negotiation group believes are necessary for an informed decision."

Harter warned against taking a "'hot tub' view of negotiation as a method of settling disputes and establishing public policy." Because industries, environmental groups, and government officials mirror the concerns of their particular constituencies, their outlook and interests will never coincide perfectly. But given the considerable failings of the present system, he concluded, "at the very least, regulatory negotiation is worth a try." ☐

Bob LaPree

Janet Mendelson

Pictured above, William Humm of the New England Environmental Mediation Center, and below, William Reilly of The Conservation Foundation. According to Reilly, "Conflict . . . is a legitimate and potentially useful part of the decision-making process."

decisions," said William K. Reilly, President of the Conservation Foundation. "It is a legitimate and potentially useful part of many decision-making processes. Under the right circumstances, conflict can create opportunities for individuals and groups to clarify their own values, goals, and objectives; to expose each other to new information and points of view; and to balance competing interests."

Though environmental negotiation generally works best when the issues are well-defined, it also may succeed in very complicated cases. (See Box: "The Hudson River Settlement.") However, it almost will certainly fail if potential parties focus so narrowly on *issues* that they fail to discern their more important *interests.*

When, for instance, the city of Seattle wanted to raise Ross Dam on the Skagit River to generate more hydroelectric power, the province of British Columbia objected because a higher dam would inundate Canadian territory. Had they remained focused exclusively on the apparent issue—the impact of raising the dam—no solution would have been possible. When they looked more closely at their own interests, however, a compromise began to emerge.

Seattle had originally agreed to compensate property-owners in British Columbia whose land would be flooded if the city decided to build a higher dam. Several years later, the provincial government asked the International Joint Commission, a standing body with representatives from the United States and Canada, to examine the environmental consequences of raising Ross Dam. While the International Joint Commission was conducting that investigation, it encouraged the city and province to begin negotiations with a mediator from the Institute of Environmental Mediation in Seattle.

Soon after the talks started in April 1982, the parties realized their real interests were broader than the height of Ross Dam. Seattle needed to supplement its power supply; British Columbia wanted to preserve land. In exchange for not building the dam, the province agreed to provide the city with power from Canadian sources. Their agreement, which was concluded in March 1983, will remain in force for the next 80 years. If the province subsequently decides not to supply power to Seattle, the city will be free to raise Ross Dam, and the cost of its construction will be borne by British Columbia.

Legislative Reciprocity

A much more complicated issue in Canadian-American relations is acid rain. Though Robert E. Stein, the President of Environmental Mediation International, a private non-profit organization with offices in Washington and Ottawa, concedes that the dispute cannot be resolved by informal negotiations, his group was active in dealing with a related matter: Canadian reciprocity on pollution controls.

Section 115 of the U.S. Clean Air Act permits the Administrator of the Environmental Protection Agency to modify state air-pollution control plans if emissions from a state harm countries whose laws provide that it will modify its own air-pollution countrol standards if its emissions are harming the United States. Stein's group was asked to determine if Canadian laws and practices entitled that country to the benefits of Section 115.

Working with a Canadian colleague, Stein found that Canada was substantively in line with that provision but had no law that explicitly established the principle of reciprocity on air pollution.

Canada responded swiftly. "Some two weeks after the report was submitted to the two governments," said Stein, "legislation was enacted by the Canadian Parliament setting forth a form of legislative reciprocity." Even though environmental negotiation may not completely resolve a dispute, it can sometimes lessen its severity.

Regulatory Negotiation

Face-to-face discussions may also become part of a government agency's rule-making process. The rulemaking process now requires an agency to develop substantive scientific data and seek public comment before it can promulgate an environmental regulation. Several years may pass before the final regulation goes into effect. What happens next? "Everyone sues us," said Joseph A. Cannon, an Associate Administrator at the U.S. Environmental Protection Agency (EPA).

To reduce the time and litigation surrounding its rules, EPA recently began a pilot project that will use environmental negotiations to develop new regulations. (See box: "Making Up the Rules.") If the project succeeds, negotiated rule-making may be more widely applied at EPA. Other federal agencies are also considering negotiated rule making as a mechanism to reduce the time and cost of ultimately arriving at an acceptable final rule.

Because it is meant to complement rather than supplant the judicial process, environmental negotiation "must operate within the parameters of existing law," said Gail Bingham. "This has to be incorporated into the negotiation process, and the outcome must be evaluated with respect to how well it can stand a legal test if it were to be challenged."

Janet Mendelson

Gail Bingham of The Conservation Foundation: ". . . the outcome must be evaluated with respect to how well it can stand a legal test if it were to be challenged."

Though environmental negotiation may help to resolve some disputes, it is not going to transform adversaries into allies. "In our experience," said Gerald W. Cormick, who has mediated a number of disputes in the West, "actual or threatened litigation is often a necessary prerequisite to the willingness of a proposing party to negotiate and is the source of power and influence that brings the parties to the table and mediation."

While no one in the field believes environmental negotiation is going to work miracles, it can, if wisely applied, play an important role in disputes between industry and environmental groups.

In addition, it could yield more general long-term benefits. Hours spent together in good faith negotiations over tough issues might produce greater mutual respect and understanding among participants that could pay dividends when controversies arise in the future. More frank, open, and frequent communication among environmental, industrial, and governmental leaders could be an indirect result of environmental negotiation that in the long run would produce greater benefit than successful resolution of the specific dispute negotiated.

Hudson River Showdown

The Hudson River began boiling with controversy in 1963, soon after Consolidated Edison of New York announced plans to build a hydroelectric facility near Storm King Mountain. When the parties finally agreed to negotiate their differences in 1979, they needed a very large table for the five electric utilities, four government agencies, and three environmental groups that took part.

The initial issue was Storm King, and the lineup for and against it was what one would expect: the utilities on one side, environmental groups on the other, and the federal and state governments trying to fulfill their statutory responsibilities. But over time, Storm King began to recede from the picture and the project ultimately was dropped. The question then became: how should the Hudson River be used?

Russell Train, the former Administrator of the Environmental Protection Agency and President of the World Wildlife Fund, agreed to mediate the dispute, and negotiations began in August 1979.

The battle lines and alliances became blurred. EPA and local fishermen, for instance, strongly favored the use of cooling towers for generating plants along the river. The utilities were opposed because each tower would cost $350 million to build and $100 million a year to operate. Environmentalists sided with the utilities against the towers because of their visual and ecological impact.

The talks came close to collapse, but Train and the negotiators persisted. One of the participants was Joseph D. Block, Executive Vice President and General Counsel of Consolidated Edison. In a recent interview, he said, "Russell Train played a very, very important role in getting this thing done. It was not simply because of his being a national figure, although that certainly helped. He had the technique and the demeanor to conduct himself in such a fashion that he just held everybody together. There were times when the negotiations were really loud and vehement, but he was always able to keep the meetings going."

If the negotiators began by looking for hardware to resolve the dispute, they soon found little in the way of hard data to support one technological solution over another. On the issue of how many fish would be killed by the cooling towers, for example, there were some 40,000 pages of studies and testimony—and, obviously, no consensus.

"The big breakthrough came when we found out that we could have a settlement without cooling towers," said Block. "The EPA at the outset argued that they wouldn't accept any kind of settlement unless it had at least one cooling tower in it. Even that was overcome as the settlement package was developed."

For additional reading on environmental negotiation see: Philip J. Harter, "Negotiating Regulations: A Cure For Malaise," The Georgetown Law Journal, *Vol. 71, No. 1, October 1982. Also, subscriptions to* Resolve: A Quarterly Newsletter on Environmental Dispute Resolution *are available at no charge from: The Conservation Foundation, 1717 Massachusetts Avenue, N.W., Washington, DC 20036.* ☐

Scenic Hudson, Inc.

Signers of the Hudson River settlement, left to right: George Berry, President, Power Authority of New York; Robert Boyle, President, Hudson River Fisherman's Association; Francis Reese, Chairman, Scenic Hudson Association; and Russell Train, President of the World Wildlife Fund and mediator of the dispute.

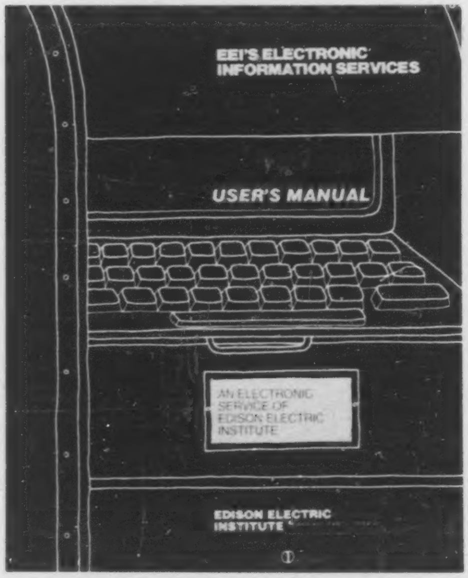
Signed in December 1980, the agreement, which details use of the lower Hudson River by the utilities, remains intact. "Because all the conditions were so ripe for settlement," said Block, "there's been no backing off or chiseling. Everybody's going along with the documents as written." ☐

For an excellent account of the Hudson River negotiations see: Allan R. Talbot, Settling Things: Six Case Studies in Environmental Mediation *(Washington, D.C.: The Conservation Foundation, 1983).*

Computerized Information Service Portends Success

Language, one of the first social barometers of technological change, evolves as words are created or conscripted to describe or define something new. In short order, old words are applied in contexts totally unrelated to those that gave rise to them—or, worse yet—exiled to the category of jargon, destined to elicit raised eyebrows from the most linguistically orthodox. "State-of-the-art" and "user-friendly" are two such terms; as the computer revolution has spread, these descriptions have replaced "sophisticated" and "nonthreatening" for a universe of current and potential computer enthusiasts.

Even if these terms seem trendy, what they describe is the product of years of intensive planning. The pilot test of the Edison Electric Institute's (EEI) Electronic Mail and Industry News Service, now in its seventh month, underscores this point. EEI set out to introduce its members to the most user-friendly state-of-the-art information transfer technology available. The challenge was to offer both a channel of rapid communication and an information file that included up-to-the minute industry news to an audience whose information and communication needs and computer skills range widely: senior and middle managers representing a variety of disciplines, librarians, public information specialists, and data processing experts. No small order.


EEI'S ELECTRONIC INFORMATION SERVICES
USER'S MANUAL
AN ELECTRONIC SERVICE OF EDISON ELECTRIC INSTITUTE
EDISON ELECTRIC INSTITUTE

Mark Borchelt

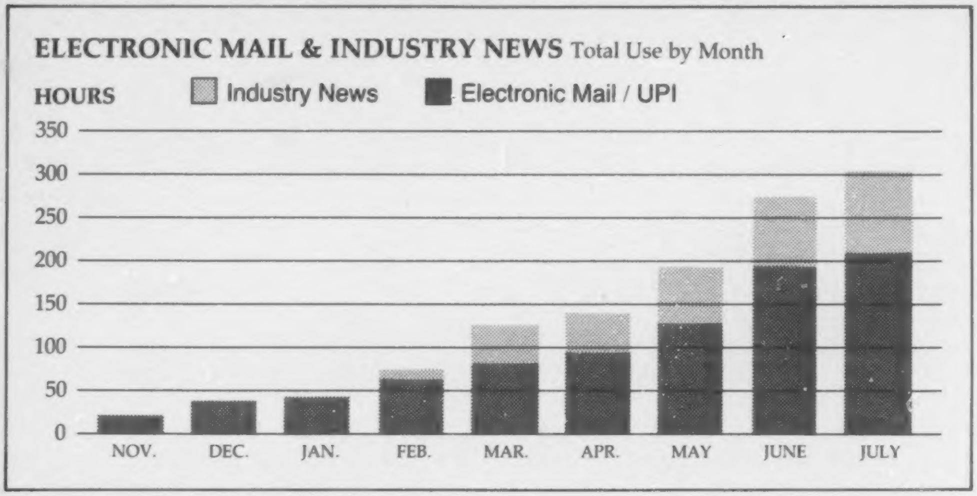
At this stage in its evolution, it appears Electronic Mail and Industry News is meeting that order: the Industry News file is maturing into one of the most industry-specific data files and news services available, and the electronic mail feature of the service now enables system users to communicate with one another more rapidly and cost-effectively than ever. What began as a trial with seven communication executives is now one with 155 other users. News has spread fast—if not electronically—that the Electronic Mail and Industry News Service fills the electric utility industry's growing need for up-to-the-minute news and instant communication capability.

What precisely Is Electronic Mail and Industry News?

The Electronic Mail and Industry News Service is a multi-faceted electronic information-transfer system. Almost any data terminal, personal computer, or word processor outfitted with a modem can access the service. The electronic mail feature enables those holding system passwords to write and edit letters or messages and send them electronically to other password holders. A message is stored in the recipient's "electronic" mailbox until called up. Transmitted within seconds, the message appears exactly as written and can be printed out by the recipient if a hard copy is desired, or stored and called up again, or both.

No one is a stranger to the frustrating experience of having telephone messages go awry or letters delayed in transit. Electronic mail eliminates both problems through its speed and accuracy. Letters can be sent to large distribution lists, carbon- or blind-copied to multiple password holders, and scanned for a one-line subject and then read later. Moreover, correspondence can be kept confidential if the password holder does not share his or her unique password with others. Com-

Contributed by the Information and Publishing Services Department of Edison Electric Institute



paring total monthly costs for the password and on-line time with traditional alternatives, users find that electronic mail is often cheaper than long-distance telephoning or the postage required for mass mailings, adding cost-effective to the list of adjectives describing the service.

In addition to this communication capability, the Electronic Mail and Industry News Service also offers a highly refined, continually updated news service and industry data file. News Bureau, a particularly valuable system component, offers participants EEI's daily news summaries, United Press International by keyword search, the Atomic Industrial Forum's Infowire Service, and Media Watch, a daily annotated bibliography of industry-related stories in over 100 periodicals that discuss the electric utility industry. Other system options include EEI policy papers, library news, statistical information—in short, a wealth of materials germane to the electric utility industry and available to it and its affiliate organizations exclusively. One of the most popular options of the Industry News file is the cogent rate and regulatory information provided by EEI's Rate Regulation Department, whose on-line database, another part of the EEI electronic information service, is a nationally respected model for managing information with a long shelf-life. The Industry News Service also includes contributions from the Atomic Industrial Forum and the Electric Power Research Institute. Their newsletters, statistics, and resource catalogues keep users up to date on Forum and EPRI activities, products, and services.

Although still in the pilot-test stage of development, Electronic Mail and Industry News already has demonstrated its usefulness. Companies using the electronic mail capability—both internally and externally—report it enhances office productivity. As one company which employed its internal communication capability in nuclear power drills demonstrated, its uses are only as limited as the imaginations of its password holders. Similarly, the Industry News file has proven its value. And, because the file is shaped continually to match the needs of its users, whose responses to new options indicate precisely what kind of information the electric utility industry requires, its value will grow.

The efficacy of electronic information technology is a reality. EEI's test of Electronic Mail and Industry News tells us that fact—plus a great deal more. While computer magazines report a trend on the part of senior management to shy away from desk top terminals as if they were little more than fancy typewriters, the electric utility industry once again demonstrates the clear vision that has made its leadership excellence a given since Pearl Street. The growing number of electric utility industry managers at all levels both using and demanding state-of-the-art, user-friendly services and equipment indicates an industry founded upon and dedicated to service through technological change. □

Networks Of Power

Thomas P. Hughes
The Johns Hopkins University Press, 1983
Baltimore, Maryland, 474 pp.

By Mark Reynolds

Thomas Edison grabbed headlines in October of 1878 when he announced plans to bring electric lights into downtown New York City, substituting electricity for gas at a lower cost. The *New York Sun* described an amazing system of dynamos, underground distribution mains, meters, and incandescent lamps which would furnish electricity within half a mile of centrally located generators in major cities. In fact, in 1878, Edison had no generator, no practical incandescent lamp, much less a developed system of distribution. What he had was a vision.

The Edison Electric Illuminating Company began commercial operation in New York City in September of 1882. Humble by modern standards, the Pearl Street Station marks the first practical expression of Edison's vision—a vision which finds its current expression in the massive technological and economic network that has made electricity one of the most commonplace amenities of the modern world. Like so many aspects of modern life which we take for granted, the electric utility industry is actually a complexly revealing reflection of our culture. Power systems are cultural artifacts, embodying the social values, ideas, and institutions of the society that produces them.

In his new book, *Networks of Power: Electrification in Western Society, 1880-1930*, Thomas P. Hughes examines the electric utility industry in its historical and cultural context. He investigates not only the inventors and their new technology, but also the social, economic, and political factors that influenced the growth and development of the industry during its formative years. Hughes postulates that the expanding technology of the electric utilities represents the causes and effects of social change. His book is not simply a history of the external factors that shaped technology, nor is it only a history of the internal dynamics of technology. Rather it is a history of technology and society.

Hughes maintains that the history of all large-scale technologies can be studied as a history of systems. The development of Edison's design, from original concept to profitable enterprise, provides Hughes with a paradigm for the way such systems evolve. Edison was not the only inventor with a generator and incandescent lamps.

However, Edison is remembered while the others are forgotten because only he took his invention further and introduced a system of lighting. The organizing principles Edison established integrated and directed the diverse factors and components necessary to transform idea into actuality. Edison focused on inventions, and during the three years preceding the opening of his first generating station, he applied for a staggering 256 patents. Yet, to achieve his plan, Edison had to reach out beyond the laboratory to research and development, finance, and management.

The success of the first central generating station venture involved marketing strategy as well as technology. At 257 Pearl Street, the station would supply restaurants and shops the new light as a way of attracting customers, and illuminate offices and workplaces without creating the hazardous and noxious fumes associated with gas lighting. Moreover, by serving the Wall Street district, the Pearl Street station would catch the attention of the financiers and investors needed to fund Edison stations elsewhere.

Francis Jehl, a laboratory assistant at the Menlo Park research facility, wrote that "Edison had his plans figured out as a great general figures out his battle strategy before the first cannon is fired." Writing in private to an associate, Edison himself outlined his creative process somewhat differently:

> The first step is an intuition, and comes with a burst, then difficulties arise—this thing gives out and [it is] then that 'Bugs'—as such

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> little faults and difficulties are called—show themselves and months of intense watching, study and labor are requisite before commercial success or failure is certainly reached.

Hughes demonstrates that, in spite of his overarching strategy, the various 'Bugs' which hampered Edison were central to the evolution of the industry. Internal forces alone did not direct its growth; the system grew (both in America and Europe) within a context of geographical, economic, political, and organizational factors. Growth was not preordained; it was usually promoted, with new systems emerging to solve major problems in old ones.

Hughes borrows the phrase "reverse salients" from military historians to explain the development of systems through the identification and solution of critical problems. "Reverse salients" refers to sections of an advancing front or line that have fallen back, and it is an apt metaphor for evolving technological systems that exhibit many of the irregular and unpredictable qualities of a military front. Defining such reverse salients (or what Edison labeled 'Bugs') is the essence of the creative process: the inventor structures an amorphous challenge into a set of problems that are believed to be solvable.

The first major type of electric system, direct current, had a reverse salient in that such electricity was uneconomical to transmit. Other inventors introduced alternating current systems as a solution to this problem (though lacking a practical motor, this system too had its drawbacks). The two conflicting systems, promoted by Edison and George Westinghouse, respectively, competed intensely from 1887 to 1892 in what technical journals and the popular press called "the battle of the systems."

Hughes spotlights this conflict as a prime example of how political and social elements influence systems and as a significant reminder that technological change cannot be viewed only from the perspective of the engineer or the economist. The battle ended in the 1890s, not with the destruction of either side, but with a notable resolution on both technical and organizational levels. Before a resolution was achieved, however, both parties resorted to unorthodox political tactics to gain their own ends. Edison, for example, played politics to get a Westinghouse alternating current generator installed in New York's Auburn State prison, campaigning that electrocution was a more humane form of capital punishment than hanging. No sooner had the first electrocution taken place in August of 1890 than did Edison turn around and launch a publicity campaign asking: do you want the executioner's current in your home?

Thomas Edison with Oskar von Miller, an early pioneer of power systems in Germany.

Hughes devotes three chapters of his study to examining the evolution of electric power systems in three major cities: Berlin, Chicago, and London. During the years from 1890 until the first World War, utility companies concentrated on supplying electricity to heavily populated and industrial urban centers. Though technological advancements had cleared the way for industry growth, the utilities increasingly confronted other institutional contenders for authority over economic development and social change. Decisions by utility managers during this period shaped the character of power systems more forcefully than did the work of engineers and inventors, a change that marked a crucial shift in the history of the industry. Hughes provides a comprehensive and convincing portrait of the different political and social climates that influenced decision-making in these three world capitals: the strong-willed, rational government of Berlin, which set the stage for Germany's rapid industrialization; the combined forces of parochialism in London and Britain's preindustrial heritage, which hampered the industry's growth there; and the relatively wide-open atmosphere of Chicago where Samuel Insull devised a municipal system that became the model for all public utilities, before he was crushed, personally and professionally, by a Depression-era backlash against big business.

The last phase of Hughes's book describes the planning and implementing of regional power systems. Comparisons among three such systems—the Ruhr in Germany, the LeHigh Valley in Pennsylvania, and Tyneside in England—support Hughes's major premise that the history of a system cannot be understood without considering the society that produces it. All three systems had the same pool of technology from which to draw, but different geographical, cultural, managerial, and engineering characteristics resulted in three very different systems—evidence that there is no best way of supplying electricity.

From the invention of the simplest devices (like the light bulb) to the completion of the grandest designs (such as harnessing water power in the Bavarian Alps), Hughes draws an absorbing account of technological development against the backdrop of international events and social history. Though he freely admits that he expects future historians to revise his model and redefine his themes, Hughes' *Networks of Power* is an impressive and original study of man's constructive power in a chaotic world. Perhaps most importantly for members of today's industry, Hughes encourages optimism—in spite of the current social, political, and economic demands that often appear to suggest chaos. Understanding the ways in which the electric utility industry met and overcame the obstacles of the past fosters a firm belief that the challenges of the future can be met and overcome. ☐

In Search of Excellence Lessons From America's Best Run Companies

Thomas J. Peters and Robert H.
Waterman, Jr.
Harper & Row, 1983
New York, New York 360 pp.

By Raymond R. Beauregard

Managing businesses for profit has become considerably more complicated since the days of Adam Smith, the eighteenth-century Scottish economist who described the free market system in his book *The Wealth of Nations,* or Jean Baptiste Say, a French economist of the early nineteenth century who believed that supply created its own demand. Since the days of Smith and Say the growth of large companies employing thousands of people and selling to millions of consumers in competitive markets (with government regulation adding complexity) has changed the business of producing and selling for profit.

In response to change over the years, many theories of management and marketing have evolved and developed, some more successful than others. It appears perhaps to be an endless process of new theories displacing old ones, which break down with testing and time.

It is unlikely and even undesirable that this process should ever end altogether. The results of research on the subject of successful management, however, reported in *In Search of Excellence,* promise to streamline the process greatly.

Peters and Waterman have researched the business practices of 14 companies selected on the basis of market and financial performance from a sample of 62 highly regarded American firms.

The message is as old and timeless as trade itself. In fact, the book is largely about people, how they feel about themselves, and how they react to conditions in the market and work places. The authors note that "there was hardly a more persuasive theme in the 14 excellent companies than respect for the individuals."

Their findings indicate that a handful of characteristics are common to all of the 14 companies. They repeatedly emphasize a few simple messages:

- Get close to the customer.
- Get close to the employees.
- Keep things lean and simple.

Evidently, too many companies do not fully understand that satisfying customers is their prime reason for being. Satisfied customers mean sales, and profits, even with tax credits, are impossible without sales.

All of the companies examined are customer intensive and, according to Peters and Waterman, "The magic—of the excellent companies—is simply service, overpowering service." Numerous examples of customer services provided by the companies are cited. Some of these services would fail even cursory accounting cost/benefit analyses but have obvious values to the companies. The excellent companies really are close to their customers. They do more than talk about treating customers as number one; they do it.

Excellent companies also know that employee attitudes affect productivity and, importantly, customer relations. Peters and Waterman point out that the companies "make people winners," "respect the individual," and let people "stand out." They also have high expectations of their employees, and provide non-monetary incentives as reinforcement. The book lists a number of approaches and philosophies that the companies follow to "be close to employees," these policies and techniques range from "full" employment policies in times of recession, to honor rolls, and even to "unabashed hoopla."

Complexity increases with size and so does the need for staff, systems, and programs. But the excellent companies keep things lean and simple. They are not hung up with the rigidity of organizational charts, job descriptions, or some notion that authority exactly matches responsibility. They want people to do a good job—but just as important—they want to get on with it.

The authors do not suggest that keeping things simple is a simple matter. Their research on how the selected companies minimize the inherent complexities of large organizations indicates that excellent companies have basic organizational forms flexible enough to respond quickly to changes in the environment. The forms differ, but according to the authors, ". . . there is only one crucial concomitant to the excellent company's simple structural form: lean staff. . . ."

Peters and Waterman are critical of the basic forms currently used by businesses. For example, they point out that "divisions invariably get too big" and the matrix form "virtually always ceases to be innovative, often after a short while." The authors propose a so-called "hybrid alternative," which they call the "Structure for the Eighties." Its major attributes—which of course remain to be tested—are simplicity, clarity, and smallness of staff.

It is a mirror of our time that the electric utility industry, which has a long history of excellence in customer services and in fostering a feeling of team effort among employees, was not considered for study. Utilities, along with financial service institutions, ". . . were thought to be too highly regulated and protected to be of interest."

The industry's long-standing adherence to customer services has blurred somewhat in recent years under the pressures of rising costs, seemingly interminable legal and financial problems, and a growing number of advocacy groups who have picked at every seam of the industry's infrastructure. Under such pressures it became necessary to concentrate efforts on seeking relief and solutions in the public hearing rooms of regulatory bodies and in the courtrooms of the land. As a result, contacts with customers have eroded and misunderstandings have increased. The stress also has taken its toll on human relations within companies.

For these reasons and more, the book may hold special meaning for the utility industry. It can serve as a reminder of the values of providing "overpowering" customer services and of maintaining a high level of employee involvement in company and community affairs. ☐

Raymond Beauregard is Corporate Economist for Northeast Utilities Service Company.

Sales Down for All Utilities in '82

Electricity sales declined in the United States last year for the first time since World War II. The 2.65 percent overall 1982 reduction was experienced equally by both investor-owned and publicly-owned utilities.

Investor-owned utilities experienced a substantial sales loss in the industrial sector—8.45 percent—while sales in the commercial and residential sectors were up by 2.15 and 0.35 percent respectively. For the public utilities, sales dropped in both the commercial and residential sectors, but the decline was more significant in the commercial sector—16.35 versus 1.51 percent. (See Table 1.)

Investor-owned utilities experienced declines in total sales in 31 states; public utilities experienced declines in 27. (See Table 2.) In most states, the percent change between 1981 and 1982 sales differs greatly for the two types of utilities because investor-owned utilities rely more heavily on densely popu-

Contributed by the Statistics Department of Edison Electric Institute.

Table 1. Electric Utility Sales In Gigawatt Hours by Region*

	Investor-Owned				Publicly-Owned			
Division/State	Total to Ultimate Customers	Residential	Commercial	Industrial	Total to Ultimate Customers	Residential	Commercial	Industrial
1982 Total United States	1,585,785	528,969	429,036	575,364	507,807	200,271	85,051	195,306
1981 Total United States	1,628,986	527,119	420,014	628,481	521,688	203,360	101,684	191,160
Percent Change	−2.65	0.35	2.15	−8.45	−2.66	−1.51	−16.35	2.16
1982 New England	70,841	26,491	23,046	19,827	6,660	2,757	1,248	2,291
1981 New England	71,078	26,357	22,398	20,827	6,765	2,770	1,316	2,326
Percent Change	−0.33	0.51	2.89	−4.80	−1.55	−0.46	−5.16	−1.50
1982 Middle Atlantic	229,418	75,072	71,077	78,340	19,010	3,114	1,044	8,238
1981 Middle Atlantic	237,944	75,417	70,045	87,287	18,694	2,998	1,146	8,273
Percent Change	−3.58	−0.46	1.47	−10.25	1.69	3.86	−8.90	−0.42
1982 East North Central	318,290	97,856	75,420	132,540	34,226	17,922	5,759	8,924
1981 East North Central	338,377	99,035	75,888	151,197	35,010	18,244	7,524	7,996
Percent Change	−5.94	−1.19	−0.62	−12.34	−2.23	−1.76	−23.45	11.60
1982 West North Central	93,800	31,625	25,340	34,701	55,221	27,875	12,631	12,042
1981 West North Central	94,530	30,227	24,408	37,787	52,962	26,367	14,535	10,092
Percent Change	−0.77	4.63	3.82	−8.17	4.26	5.71	−13.09	19.32
1982 South Atlantic	303,258	110,769	81,767	99,879	71,641	36,726	13,681	19,733
1981 South Atlantic	307,988	112,891	77,172	107,291	70,421	38,286	14,707	15,808
Percent Change	−1.54	−1.88	5.95	−6.91	1.73	−4.07	−6.97	24.82
1982 East South Central	64,574	21,641	14,218	25,605	123,818	42,346	7,705	72,834
1981 East South Central	68,004	21,994	13,903	27,695	129,261	44,111	12,204	71,363
Percent Change	−5.04	−1.60	2.27	−7.55	−4.21	−4.00	−36.86	2.06
1982 West South Central	249,857	75,625	56,597	107,834	56,378	25,807	12,176	14,615
1981 West South Central	249,976	72,267	53,730	114,378	54,843	25,856	14,929	11,638
Percent Change	−0.05	4.65	5.34	−5.72	2.79	−0.18	−18.44	25.57
1982 Mountain	80,735	25,683	23,903	28,972	33,925	11,909	8,154	12,490
1981 Mountain	82,380	24,952	23,331	31,719	37,091	11,877	11,682	12,051
Percent Change	−2.00	2.93	2.45	−8.66	−8.53	0.26	−30.20	3.64
1982 Pacific	168,525	62,338	56,229	44,579	104,083	30,533	21,789	43,570
1981 Pacific	172,058	62,020	57,648	47,203	113,723	31,505	22,461	51,308
Percent Change	−2.05	0.51	−2.46	−5.56	−8.47	−3.08	−2.99	−15.08
1982 Alaska & Hawaii	6,488	1,870	1,437	3,086	2,844	1,281	865	570
1981 Alaska & Hawaii	6,651	1,959	1,491	3,097	2,918	1,346	1,180	305
Percent Change	−2.45	−4.54	−3.62	−0.36	−2.53	−4.82	−26.69	86.88

*Parts do not add up to totals due to elimination of miscellaneous customer classifications

Note: In 1982 a major reclassification of commercial and industrial customers occurred.

lated and industrialized service territories for sales than public utilities do. An exception to this is in Oregon and Washington where the public utilities rely heavily on large industrial customers, which were hit hard by the recession. Consequently, total sales by public utilities in those two states showed large drops, whereas the investor-owned utilities in the two states were able to offset industrial sales declines with slight increases in commercial and residential sales. ☐

Table 2. Electric Utilities Sales In Gigawatt Hours By State

	Investor-Owned			Publicly-Owned		
State	**1982**	**1981**	**Percent Change**	**Percent Change**	**1982**	**1981**
Maine	7,983	7,923	0.75	−5.29	215	227
New Hampshire	5,698	5,653	0.79	0.91	442	438
Vermont	3,183	3,140	1.36	−2.45	756	775
Massachusetts	29,068	29,055	0.04	3.53	4,253	4,108
Rhode Island	4,917	5,008	−1.81	0.00	20	20
Connecticut	19,992	20,299	−1.51	−18.63	974	1,197
New York	89,303	90,875	−1.72	1.35	15,671	15,462
New Jersey	48,113	48,960	−1.72	7.14	690	644
Pennsylvania	92,002	98,109	−6.22	2.36	2,649	2,588
Ohio	93,144	106,765	−12.75	−2.91	7,413	7,635
Indiana	46,668	47,676	−2.11	3.33	9,124	8,830
Illinois	86,925	89,747	−3.14	−7.56	6,556	7,092
Michigan	58,745	61,629	−4.67	−6.57	5,491	5,877
Wisconsin	32,808	32,560	0.76	1.18	5,642	5,576
Minnesota	24,254	24,658	−1.63	−2.51	9,854	10,108
Iowa	18,584	18,867	−1.49	−2.41	5,956	6,103
Missouri	29,658	29,938	−0.93	2.82	10,696	10,403
North Dakota	3,495	3,135	11.48	3.00	2,540	2,466
South Dakota	2,539	2,492	1.88	1.35	2,472	2,439
Nebraska	—	—	—	13.27	16,660	14,708
Kansas	15,270	15,440	−1.10	4.57	7,043	6,735
Delaware	4,366	4,484	−2.63	−7.93	1,091	1,185
Maryland & D.C.	39,900	40,517	−1.52	−1.56	1,763	1,791
Virginia	44,676	44,346	0.74	−3.99	5,629	5,863
West Virginia	19,706	20,885	−5.64	2.74	75	73
North Carolina	50,541	51,671	−2.18	8.45	15,871	14,634
South Carolina	29,180	30,289	−3.66	9.60	12,174	11,108
Georgia	40,149	40,377	−0.56	−5.65	14,699	15,579
Florida	74,739	75,419	−0.90	0.75	20,340	20,188
Kentucky	22,515	24,051	−6.38	0.13	27,221	27,186
Tennessee	1,051	1,134	−7.31	−3.41	68,281	70,689
Alabama	28,464	29,903	−4.81	−14.11	17,811	20,736
Mississippi	12,544	12,916	−2.88	−1.36	10,505	10,650
Arkansas	16,477	17,382	−5.20	−8.07	5,811	6,321
Louisiana	51,103	53,815	−5.03	−2.61	7,063	7,252
Oklahoma	25,125	24,115	4.18	15.15	10,976	9,532
Texas	157,152	154,664	1.60	2.49	32,528	31,738
Montana	6,619	6,309	4.91	−19.48	3,816	4,739
Idaho	13,578	14,405	−5.74	8.76	2,147	1,974
Wyoming	5,648	5,170	9.24	−6.32	2,639	2,817
Colorado	14,994	14,845	1.00	−2.59	7,461	7,659
New Mexico	7,178	7,142	0.50	−7.28	2,814	3,035
Arizona	14,359	16,466	−12.79	−12.70	11,290	12,933
Utah	9,501	9,285	2.32	0.20	2,517	2,512
Nevada	8,858	8,758	1.14	−12.73	1,241	1,422
Washington	20,886	20,327	2.75	−9.34	50,516	55,720
Oregon	24,758	24,680	0.31	−15.20	11,802	13,917
California	122,881	127,051	−3.28	−5.26	41,765	44,086
Alaska	182	190	−4.21	−2.54	2,844	2,918
Hawaii	6,306	6,461	−2.39	—	—	—

Earnings Per Share Down 8.4 Percent

Earnings per share of the investor-owned electric utility industry were 76 cents for the first quarter of 1983, down 8.4 percent compared to the same quarter for 1982. First quarter net income available for common stock dividends showed a 2.5 percent increase to $3,506 million, but the average number of common shares outstanding increased by 11.4 percent. The rate of change in quarterly earnings per share has now declined for each quarter since the first quarter of 1982.

The first quarter 1983 decline in earnings per share largely reflects a 10.1 percent decline in non-electric utility operating income, the majority of which represents income from gas sales by combination companies. Milder than normal winter weather caused part of the decline.

Total operating revenues were at $25,466 million for the first quarter, up 1.6 percent, as the effects of rate increases granted during 1982 were partially offset by a 3.2 percent decline in sales, again attributable to the mild winter, as well as to the continued effects of the economic downturn.

Total electric operating expenses increased 1.1 percent, to $20,885 million, during the first quarter, although fuel expenses fell 8.6 percent as a result of reduced sales and lower fuel costs. The ratio of electric operating expenses to electric operating revenues declined slightly in the first quarter to 82.0 percent, compared with 82.4 percent for the first quarter of 1982.

A continued high level of construction in the industry pushed the allowance for funds used during construction (AFUDC) up 19.8 percent as construction work in progress increased 16.8 percent. AFUDC increased to 45.8 percent of net income before preferred dividends, up 6.0 percent from a year ago.

Interest coverage before income taxes and with AFUDC was 2.90 for the first quarter of 1983, up from the 2.85 times coverage in the first quarter of 1982. Long-term debt increased 8.3 percent from March 31, 1982 to March 31, 1983. Over the same period, short-term debt and long-term debt currently due declined 19.1 and 11.8 percent, respectively.

Return on Average Common Equity Declines

Total capitalization increased 9.7 percent from March 31, 1982 to March 31, 1983. The industry's equity ratio, bolstered in part by an increased participation in dividend reinvestment programs, increased from 38.6 percent to 39.4 percent over the same twelve month period. The return on average common equity declined slightly from 13.4 percent for the calendar year 1982 to 13.2 percent for the 12 months ending March 31, 1983. Debt, excluding short-term debt, decreased from 49.4 percent of capitalization as of March 31, 1982, to 48.8 percent on March 31, 1983.

Bond Issues at $1.7 Billion

The investor-owned electric utility industry issued $1.7 billion in pollution control revenue bonds during the twelve months ending March 31, 1983, at an average yield of 11.0 percent, according to EBASCO Services, Inc. As a result of not having to finance those projects with taxable corporate bonds, the industry and the rate-paying consumer realized a net savings of about $32 million for the period, based on a 46 percent statutory corporate tax rate. Based on data obtained from Moody's Investor Service, Inc., and EBASCO, Edison Electric Institute estimates that the $11.6 billion in tax exempt pollution control revenue bond financings issued since 1974 have provided ratepayers with net savings of approximately $850 million.

Tables 1 and 2 are based on unaudited reports received from electric utilities. These utilities account for about 94 percent of the industry's revenues. The data was expanded to represent the entire investor-owned electric utility industry. □

Contributed by the Finance Department of Edison Electric Institute

Table 1
INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY
STATEMENT OF INCOME
(Unaudited)
(Millions of Dollars)

	Three Months Ended			Twelve Months Ended		
	March 31,		%	March 31,		%
	1983	1982 (R)	Change	1983	1982 (R)	Change
Total Electric Operating Revenues	$25,466	$25,076	1.6	$101,556	$96,697	5.0
Electric Operating Expenses						
Fuel	8,448	9,243	(8.6)	35,311	37,905	(6.8)
Other Operation & Maintenance Expenses	6,518	5,889	10.7	25,349	21,821	16.2
Depreciation & Amortization	1,998	1,823	9.6	7,652	6,983	9.6
Taxes Other Than Income Taxes	1,921	1,827	5.2	7,276	6,785	7.2
Income Taxes (Federal & Other)	713	944	(24.5)	3,202	2,726	17.5
Provisions For Deferred Income Taxes—Net	619	276	124.3	2,252	1,978	13.9
Investment Tax Credit Adjustments—Net	668	654	2.1	2,154	1,515	42.2
Total Electric Operating Expenses	20,885	20,656	1.1	83,196	79,713	4.4
Electric Utility Operating Income	4,581	4,420	3.6	18,360	16,984	8.1
Other Utility Operating Income	534	594	(10.1)	998	997	0.1
Total Utility Operating Income	5,115	5,014	2.0	19,358	17,981	7.7
Other Income & Deductions—Net	426	462	(7.8)	1,512	1,742	(13.2)
Allowance For Other Funds Used During Construction	1,164	889	30.9	4,302	3,250	32.4
Total Income	6,705	6,365	5.3	25,172	22,973	9.6
Interest On Long-Term Debt	3,010	2,766	8.8	11,756	10,532	11.6
Other Interest Expenses & Charges	246	376	(34.6)	1,343	1,626	(17.4)
Allowance For Borrowed Funds Used in Construction (Cr.)	(751)	(710)	5.8	(3,018)	(2,698)	11.9
Total Interest & Charges	2,505	2,432	3.0	10,081	9,460	6.6
Net Income Before Extraordinary Items	4,200	3,933	6.8	15,091	13,513	11.7
Extraordinary Items	(17)	88	—	13	74	(82.4)
Net Income	4,183	4,021	4.0	15,104	13,587	11.2
Preferred Stock Dividends Declared	677	602	12.5	2,603	2,322	12.1
Net Income Available for Common	3,506	3,419	2.5	12,501	11,265	11.0
Common Stock Dividends	2,472	2,162	14.3	9,192	7,850	17.1
Retained Earnings	1,034	1,257	(17.7)	3,309	3,415	(3.1)
Earnings Per Share*	0.76	0.83	(8.4)	2.84	2.84	0.0
Dividends Per Share*	0.54	0.52	3.9	2.09	1.98	5.6

(R) Revised

*Based on average shares collected quarterly from respondents and adjusted for stock splits.

NOTE: The income statement is a "net" or "consolidated" statement. The duplicative effect of including resale revenues by one investor-owned electric utility to another has been eliminated.

Table 2
INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY
Balance Sheet
(Unaudited)
Report as of March 31, 1983 and 1982

	(Millions of Dollars)		Change
ASSETS	**1982**	**1981**	**(%)**
Utility Plant[a]			
Utility Plant (Including Nuclear Fuel)	$254,495	$237,391	7.3
Less Accumulated Depreciation	70,346	64,105	9.7
Less Property-Related Accumulated Deferred Income Taxes	3,113	2,738	13.7
Total	$181,136	$170,548	6.2
Construction Work in Progress	94,688	81,095	16.8
Net Utility Plant	$275,824	$251,643	9.6
Investments	5,950	5,165	15.2
Current Assets	31,217	28,980	7.7
Deferred Debits	7,614	6,387	19.2
Total Assets	$320,605	$292,175	9.7
LIABILITIES			
Capitalization			
Common Stock	$ 68,479	$ 60,662	12.9
Retained Earnings	31,890	28,888	10.4
Preferred Stock	30,125	27,964	7.7
Long-Term Debt	124,292	114,774	8.3
Total Capitalization	$254,786	$232,288	9.7
Current Liabilities			
Short-term Debt	$ 5,862	$ 7,246	(19.1)
Long-term Debt Due Currently	3,207	3,634	(11.8)
Other Current Liabilities	23,305	21,640	7.7
Total Current Liabilities	$ 32,374	$ 32,520	(0.5)
Deferred Credits			
Accumulated Deferred Income Taxes	$ 17,311	$ 14,920	16.0
Accumulated Deferred Investment Tax Credits	10,927	8,777	24.5
Other Deferred Credits	5,207	3,670	41.9
Total Deferred Credits	$ 33,445	$ 27,367	22.2
Total Liabilities	$320,605	$292,175	9.7

[a] Includes other utility plant of combination gas and electric companies.

Minimizing Rate Shock

"Rate shock" is a substantial increase in rates which can be experienced by a utility's customers under certain circumstances when a major new facility enters commercial operation. The most substantial contributing factor to rate shock is the simultaneous entry into rate base, i.e., the value of property on which a utility is allowed to earn a return, of large, expensive new generating plants, and the deferred financing charges on the capital which was raised to finance their construction. This sudden entry arises where a regulatory commission has not allowed current recovery of carrying charges on construction capital, by allowing a cash return on construction work in progress (CWIP) in rate base.

The best way to avoid rate shock is to allow utilities a cash return on all CWIP in their rate bases. This is in the long-term interests of ratepayers as well as utilities. Where a commission has been pursuing a policy of short-term rate suppression, by either refusing to allow a cash return on CWIP or else only a partial cash return on CWIP, the moment of truth often comes when the facility enters commercial operation. The rate consequences depend on the individual circumstances. Fuel savings, for instance, can offset, or in the most fortunate situation even obviate, the effect of the sudden large increase in rate base. In other situations, however, a major increase is necessary to cover the additions to the rate base.

Various types of "phase-in," "rate moderation," or "trending" plans have begun to appear in order to respond to rate shocks. Such plans began to be proposed in individual utility situations last year, and have so far appeared in the U.S. Congress and nine states: Connecticut, Illinois, Indiana, Iowa, Kansas, Louisiana, New Mexico, New York, and Pennsylvania. They can be categorized as follows:

- Plans affecting time of rate base inclusion,
- Plans deferring recovery of operating expenses, and
- Plans altering method of depreciation.

Plans affecting the time of rate base inclusion are before regulatory commissions in seven states: Connecticut, Illinois, Indiana, Iowa, Kansas, New Mexico, and New York. Legislation authorizing such plans has been approved in Connecticut, vetoed in New York, and is under consideration in the U.S. Congress and in Illinois. These plans can be subdivided into three subcategories:

- "Trending" proposals, beginning rate base inclusion earlier than it would otherwise begin, and ending inclusion at a later date than the date commercial operating begins (Connecticut and Indiana).
- "Negative CWIP" schemes, recouping past allowances of a portion of CWIP in rate base after a plant begins commercial operation (federal, Illinois, and New York).
- Deferred entry of part of the plant into rate base, on a fixed schedule (Illinois, Iowa, Kansas, New Mexico).

The distinction between trending and negative CWIP is a fine one. In a trending proposal, as I use the term, a utility somehow gets cash flow with respect to a project earlier than it would otherwise. As a tradeoff for this, the utility agrees that it later will defer receipt of additional cash at a time when it would otherwise be entitled to receive it. A negative CWIP plan is a give-back plan; it proposes to take cash away from a utility at a later date because a regulatory commission had, in the past, allowed cash return on CWIP. Trending is prospective; it sets new ground rules for the future. Negative CWIP is retrospective; it seeks to change existing ground rules to the detriment of the utility.

The Indiana proposal is the furthest along of all these proposals. This past January, the Indiana PSC decided in principle to integrate the cost of Public Service of Indiana's two Marble Hill plants (scheduled to go on-line in 1986 and 1988) gradually into rates by a "stair step or trended route." This method, details of which are being worked out by PSI and staff, represents the PSC's solution to the dilemma posed by its interpretation of Indiana

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statutes to preclude CWIP inclusion on the one hand, and by its conviction that rates as set traditionally without CWIP do not meet federal constitutional minimum requirements.

In response to this order, PSI filed, on July 8, a "Rate Control Plan." The plan proposes annual rate increases of approximately 8 percent for six years, beginning with the issuance of a PSC order approving the plan and continuing on November 1 of each year thereafter. These increases are intended to be in lieu of all general rate increases for the 1984–1989 period, except fuel cost adjustments which will continue to be processed under existing PSC procedures. If major adverse changes beyond PSI's control would otherwise preclude the issue of first mortgage bonds, PSI will seek PSC approval for plan modifications. PSI estimates that the cash effect of the plan, for the 1983–1986 period, will be to reduce new money requirements by $344 million (21 percent). After 1986, construction expenditures will drop sharply as the units are completed, and would be met by internally generated funds.

In Connecticut, United Illuminating Co. proposed this March, in a rate case application, a "customer/investor parity proposal," for its investment in the Seabrook project. The effect of this proposal would be to trend the plant into UI's rate base. New Connecticut legislation, which became effective in June, in effect requires the Connecticut commission, if it allows any CWIP in rate base in the future, to do so on a trending basis. This option is available for two plants only: Millstone 3 and Seabrook 1 (the first unit of a two-unit project). Connecticut Light and Power (CL&P) has filed for a rate increase in accordance with this statute. CL&P has proposed to phase in the rate impact of the Millstone 3 unit through a series of five small rate increases, three before the plant goes into service (1986), two thereafter. For CL&P customers, the alternative would be a single 20–25 percent rate increase in 1986.

In Illinois, Commission staff proposed a "negative CWIP plan" for Commonwealth Edison and Illinois Power, under which CWIP previously included in rate base for a plant would be removed from rate base for corresponding periods after a plant came on-line. AFUDC would be restored on excluded amounts; rate base eventually would be increased by the amount of negative CWIP plus the restored AFUDC. The theoretical basis for the staff's position is the "Capital Investment Recovery Illinois Model" (CIRIM). Staff justifies this as "more symmetrically passing back the benefits of lower costs realized through CWIP" to the customers who have paid rates based on CWIP.

In its orders in CWE's and IP's latest rate cases, the Commission did not adopt this plan. However, it directed CWE and IP to study the plan with staff, and to come up with a "positive and workable proposal." CWE, in its response to the Commission this June 1, expressed reluctance to adopt a negative CWIP plan and suggested adjustments to depreciation as an alternative.

The Illinois legislature has passed and sent to the governor a bill which would progressively eliminate most CWIP in rate base over a period ending in 1989. One of the provisions of this bill would require a phase-in of the negative CWIP variety in return for previous allowances of CWIP. The bill's plan is similar to the Illinois staff's CIRIM plan. The governor has until early October to sign, veto, or exercise a sort of item veto known as the "amendatory veto."

Last August, the New York PSC began an investigation on its own motion into ratemaking principles for Long Island Lighting Co.'s (LILCO) Shoreham plant. At the PSC's direction, LILCO submitted for consideration a "rate moderation plan," similar to the Illinois staff's "negative CWIP plan." Hearings on this and other proposals are underway before an ALJ. LILCO filed a rate increase application, which includes a request for rate basing of Shoreham, in May, 1983. In this application, LILCO has continued to request that its Rate Moderation Plan be adopted. New York Governor Cuomo recently vetoed a bill which would, if enacted, have mandated more restrictive ratemaking treatment for Shoreham.

The federal plan mentioned earlier is

included in H.R. 555, a bill which has passed neither house of Congress as of this writing. H.R. 555 would phase complex restrictions on the Federal Energy Regulatory Commission's (FERC) authority to include CWIP in rate base. FERC regulates only rates for sales of electricity by one utility to another. An amendment added to this bill in committee would, in effect, require FERC to consider whether implementation of a negative CWIP plan was just and reasonable in any case in which FERC allowed inclusion of most types of CWIP in the rate base.

Staggered entry of a new plant into rate base has been proposed by Iowa-Illinois Gas and Electric Co. (I-IG&E) for its portion of the new, 650 Mw coal-fired Louisa Station, in Illinois and Iowa rate cases. I-IG&E proposes phase-in over a four-year period. Iowa Power & Light Co. is proposing the same type of plan for its portion of Louisa. Sunflower Electric Cooperative is suggesting a similar plan in Kansas for a new, coal-fired unit. In New Mexico, El Paso Co. filed a stipulation agreement with the New Mexico PSC in July, 1983, which proposes a phase-in methodology for El Paso's interest in the Palo Verde nuclear plants.

Two plans have been proposed which would defer recovery of operating costs. One, in Louisiana, seeks to defer recovery of purchased power expenses. The other, in Pennsylvania, is a form of budget billing. Both are voluntary utility initiatives.

Two Louisiana utilities, Louisiana Power & Light Co. (LP&L) and New Orleans Public Service, filed general rate cases with the Louisiana commission this January. The filings, which seek to recoup the companies' costs associated with the Grand Gulf Nuclear Plant, include plans to defer operating expenses resulting from passthrough of purchased power costs for electricity from the new plant under a FERC wholesale rate. LP&L and NOPSI are both operating subsidiaries of Middle South Utilities, and the Grand Gulf Plant is owned by a generating subsidiary of Middle South. The companies' plan proposes to defer for four years portions of the purchased power costs. After a breakeven point is reached, accumulated deferrals would be recouped over five years. This type of plan is possible only where one utility has built a plant, and another has undertaken an obligation to purchase power from the plant as a means of assisting in financing the plant.

Pennsylvania Power and Light Co. (PP&L) is proposing, to moderate the impact on ratepayers of the Susquehanna No. 1 unit, a trended budget billing plan. This plan will spread the impact of the rate increase over a 16-month period.

Depreciation proposals have been made in Illinois and Pennsylvania. Both proposals are utility initiatives. CWE's proposal, in Illinois, which is a counterproposal to staff's negative CWIP plan, has already been mentioned. PP&L is the originator of the Pennsylvania proposal; which it advanced, together with its budget billing plan, to ease the impact of Susquehanna on its ratepayers.

Utilities normally use a "straight-line" method of depreciation where the cost of a new plant is recovered in equal annual amounts over the life of the plant. PP&L has proposed to use modified sinking fund depreciation for the first ten years that Susquehanna operates. If the concept is approved, PP&L would claim about $15 million a year in depreciation expense for the first year on Susquehanna. The amount would increase by about 12 percent a year until the tenth year. In the eleventh year, PP&L would switch-over to the straight line system. At that time the annual depreciation expense would be about $48 million a year on Unit 1 and continue at that level until the unit is fully depreciated. PP&L has estimated that, because of the modified sinking fund depreciation method, its rate increase request was about $28 million lower than it would have been otherwise.

CWE is proposing phasing-in of depreciation for its units as a concept. It has not, however, formally proposed any single plan, although it has offered an illustration of a possible method. ☐

CALENDAR OF MEETINGS
Edison Electric Institute

When
What
Where
Who to Contact
(Call 202/828-7400)

September 19–21
EEI Annual Roundtable Conference
Chicago, Illinois
Frances Palladini

September 19–21
EEI Rate Research Committee
San Francisco, California
David Owens

September 19–21
EEI Fire Protection Committee
Boston, Massachusetts
James Evans

September 19–21
EEI Meter & Service Committee
Dearborn, Michigan
David Soffrin

September 20–23
A.G.A.-EEI General & Plant Accounting Committees
San Antonio, Texas
George Brown

September 20–23
EEI Residential Committee Meeting & Roundtable
St. Louis, Missouri
Robert Griffin

September 25–28
EEI Commercial/Industrial Committee Meeting & Workshop
St. Louis, Missouri
Charles Taylor

September 25–28
EEI Risk Management Committee
Phoenix, Arizona
Ted Gradin

September 26–27
EEI Construction Committee
Salt Lake City, Utah
Eric Haskins

September 26–28
A.G.A.-EEI Budgeting & Financial Forecasting Committees
Denver, Colorado
Lowell Klosky

October 2–5
EEI Nuclear Operations Committee
Hampton, New Hampshire
Suzanne Phelps

October 2–5
EEI Prime Movers Committee
Portland, Oregon
James Evans

October 4–6
Electric Vehicle Council
EV EXPO '83 Electric Vehicle Exposition & Conference
Dearborn, Michigan
John Makulowich

October 5
EEI CS&M Executive Advisory Committee
Albuquerque, New Mexico
Charles Taylor

October 6–7
EEI CS&M Division Executives' Symposium
Albuquerque, New Mexico
Charles Taylor

October 5–7
EEI Statistical Committee
San Francisco, California
Thomas Daugherty

October 5–7
A.G.A.-EEI Internal Auditing Committees
Tampa, Florida
Marshall Baker

October 6–9
EEI Legal Committee
New York, New York
Robert Baum

October 9–11
EEI Compensation & Benefits Committee
New Orleans, Louisiana
James Stroop

October 9–12
EEI System Planning Committee
Philadelphia, Pennsylvania
Jamei Goellner

October 10–12
EEI Financial Conference
Palm Beach, Florida
Ted Gradin

October 10–12
EEI Security Committee
St. Louis, Missouri
Eric Haskins

October 10–14
EEI Transmission & Distribution Committee
Denver, Colorado
David Soffrin

October 12–14
A.G.A.-EEI Depreciation Accounting Committee
New Orleans, Louisiana
George Brown

October 16–19
EEI Consumer Affairs Committee Meeting & Conference
Washington, D.C.
Charles Taylor

October 19–20
EEI Hydraulic Power Committee
Denver, Colorado
James Evans

October 23–26
EEI Street & Highway Lighting Task Force Meeting & Workshop
St. Louis, Missouri
Charles Taylor

October 24–26
EEI Electrical System & Equipment Committee
Minneapolis, Minnesota
Jamei Goellner

**October 30–
November 2**
EEI Taxation Committee
Charleston, South Carolina
Ted Gradin

November 6–9
EEI Safety & Industrial Health Committee
Dallas, Texas
Melodye Turek

November 6–9
A.G.A.-EEI Customer Services Committees
San Diego, California
Robert Griffin

November 7–9
EEI Claims Committee
San Diego, California
Robert Baum

November 16–18
A.G.A.-EEI Information Systems Conference
Kansas City, Missouri
Ralph Palmigiano